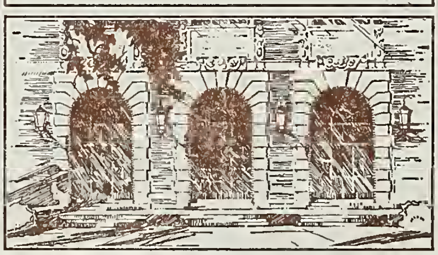

Center for Advanced Computation

UNIVERSITY OF ILLINOIS AT URBANA-CHAMPAIGN
URBANA, ILLINOIS 61801

CAC Document No. 137P

NUCLEAR POWER TO 1985: POSSIBLE VERSUS OPTIMISTIC ESTIMATES

by

Michael Rieber
Ronald Halcrow

November 1974

CAC Document No. 137P

NUCLEAR POWER TO 1985:
POSSIBLE VERSUS OPTIMISTIC ESTIMATES

by

Michael Rieber
Research Professor

and

Ronald Halcrow
Research Assistant

Center for Advanced Computation
University of Illinois at Urbana-Champaign
Urbana, Illinois 61801

November, 1974

This work was supported by the National Science Foundation (RANN), NSF Grant GI 35821A(1).

N O T E

This document is presented in preliminary form. It is subject to textual and some tabular revision. Four figures in Section II and all of Section VII have been omitted. They will be supplied in the complete document. Comments and criticism are both welcome. If the document is cited and quoted, it is requested that its preliminary status be noted.

TABLE OF CONTENTS

Page

LIST OF TABLES

SECTION I: THE COST OF NUCLEAR POWER

A. Introduction

The economic superiority of fissile or fossil electric power generation has not yet been demonstrated. Both sides have proponents, and new contracts are being let by utilities for both steam systems. Each provides a ceiling price or comparative standard for the other. In this study the cost of nuclear power is examined in order to provide a standard for coal. Nuclear safety is not examined other than for its contribution to costs.

The reliability, comprehensiveness and bases of nuclear power cost estimates are important with respect to evaluating future energy costs, economically efficient utilization of our fuel resources, and the achievement of Project Independence. In Section I, Atomic Energy Commission (AEC) estimates of nuclear power electric generation costs in 1980 are compared with those developed in this study, with two utilities seeking nuclear licenses, and with those developed by Arthur D. Little, Inc. It is found that the AEC cost estimates are relatively low. Furthermore, all cost elements are not included. Finally, if the costs are calculated at the bus-bar rather than as the cost to the utility, the increase in the estimated cost is substantial.

Section II contains an analysis of nuclear power supply forecasts and an evaluation of nuclear power plant load factors. The supply forecasts are relevant to Project Independence, but an analysis of the delays and downward revisions in the estimates points to construction problems and increasing cost of finance due to delay.

Table I-1 presents a comparison of the supply projection made in this study with those made by others. With the exception of the projected maximum for 1985, all of the esti-

TABLE I-1

Comparison of Nuclear Capacity Forecasts
(000 MWe)

	1970	1975	1980	1985
AEC Wash 1139 (1972)	5.9	54.2	132.0	280
Electrical World	6.2	56.5	128.1	--
Department of the Interior	--	50.0	120.0	215
FPC (National Power Survey)	6.0	--	147.0	--
NPC (Case III)	--	64.0	150.0	300
Atomic Industrial Forum	--	59.0	146.0	302
This Study (projected)[(1)]	--	47.8	94.6	--
(projected maximum)[(2)]	--	47.8	119.1	250.0

Sources: U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and August 1, 1973, p. 48.

[(1)] Table II-1.

[(2)] Table II-2.

mates in this study are lower than those made by any other agency. It would appear that current events may make even these relatively pessimistic estimates appear overly optimistic. This has been recognized by the AEC which reduced its 1980 estimate first to 125,000 megawatts,[1] and later to 102,000 megawatts of electricity.[2] The projections made in this study assumed a six year construction time or an eight to ten year total span between the time a plant is reported and the time it is on-line. In 1973, Atomic Industrial Forum (AIF) reported that the total time for a plant, from its inception to the time it was on-line, was between nine and ten years.[3] By the end of that year it was reported that AEC Commissioner Dixie Lee Ray had estimated that the time span for reactors was between eight and ten years.[4] If Tables II-1 and II-2 are revised based on longer construction and lead times, even the projected maximum estimates presented in Table I-1 appear to be too high. Construction delays and slippages are a continuing feature of the nuclear industry. In late 1973 it was reported that three out of six plants scheduled for 1973 were delayed until 1974.[5] In February 1974, it was reported that plants currently under construction were experiencing delays lasting between five and sixty-one months with a mean delay time of twenty-four to twenty-five months.[6] In March it was reported that over 50 percent of the plants then under construction had lost between one and thirteen months between September 1973 and March 1974. The median slippage was three to six months.[7] This does not include those plants recently cancelled or postponed for financial reasons or because of revised consumption forecasts.

It has been hoped that by changing the regulations concerning hearings and licensing, the civilian nuclear power program can be accelerated. A study by the Federal Power Commission indicates that this hope may be forelorn. The study indicates that of 30 nuclear plants orginally scheduled for

operation prior to the summer of 1973, 29 units were late. A large number of reasons are cited with many facilities citing more than one reason. In order, these include the following: changes in regulatory procedures (14), late delivery of major equipment (13), poor productivity of labor (12), shortages of construction labor (10), prolonged regulatory procedures (10), strikes by construction labor (9), equipment component failure (5), rescheduling of associated facilities (5), legal challenges (5), strikes by equipment manufacturing industries (2), weather (2), and necessary approval by local authorities (2). Of the total of 89 citations, 25.8 percent were equipment related, 37.1 were labor related, 27.0 percent were regulatory related, 5.6 represented legal challenges, while weather and local authorities accounted for the remaining 4.5 percent.[8] In another study, the Federal Power Commission analyzed construction delays in the 28 nuclear plants that were scheduled to become operational in 1974. It found that 32 plant-months of delay had been caused by public law suits or changes in regulatory requirements, but 229 plant-months of work had been lost through low labor productivity and shortages, late deliveries, or breakdowns of components and similar economic or technological failures.[9]

In a later study, it was found that modifications in licensing and regulatory requirements accounted for 85 percent of the delays cited for the 46 plants covered. However, this accounted for only 42 percent of the total delay time. More specifically, review, public hearing problems, intervenor tactics, and regulatory work accounted for only a total of nine percent of the delay. Non-hearing delays accounted for 49 percent of the total delay time. This included, for example, late delivery of components, labor shortages, and labor immobility. Of the 46 plants, no plant cited less than two reasons; the average number of citations was six to seven.[10]

Because nuclear power plants cost more per kilowatt to build than fossil plants, to be economic the fuel cycle costs must be low enough to offset the difference. The amount that must be offset is inversely proportional to the load factor and directly proportional to the capital cost. Furthermore, because the ratio of fuel cycle to total costs is higher for fossil than it is for nuclear plants, the cost advantage of nuclear over fossil fuel plants is directly proportional to the assumed load factor. In its cost comparisons, the AEC has almost consistently used an 80 percent load factor for its nuclear plants. In Section II it is shown that the historical load factor has been about 65 percent, or lower.

In its recent forecast, the AEC, Office of Planning and Analysis, reduced its operating capacity assumption to 75 percent rather than the 80 percent capacity upon which it had formerly counted. The discussion in Section II indicates that even 75 percent is considerably higher than the historic averages. Therefore, in examining Table I-1, it should be remembered that the estimates in the table should be reduced to 60 or 70 percent of those tabulated in order to arrive at the amount of electricity that can be expected to be available to the consumer.

Section III presents a complete methodology for the estimation of fuel cycle costs from the mine and mill, through the reactor, to storage or recycle. Although the AEC in its nuclear cost analysis, has not published a consistent accounting system, the methodology is derived from AEC documents and a study by the NUS Corporation.(11) The procedure is sufficiently detailed to allow anyone with better numbers to make his own estimates.

The fuel cycle costs developed are greater than those reported by the AEC by at least a factor of two. Major differences arise due to differences in cost escalation, mining and milling, and enrichment costs.

Sections IV and V review the components of the fuel cycle. Because 1980 costs are forecasts, these sections review the literature in order to assess probable per unit component costs. It is argued that the unit costs used in this study are conservative. Section IV is devoted to uranium mining and milling. Section V reports the remaining component costs.

Capital and other non-fuel costs are discussed in Section VI. Given the lack of consistency, inadequate reporting, and multiple bases used, most of this section is qualitative. Much that has been reported must be taken on faith or not at all. Even when direct capital costs are given, escalation has been at less than market indicated rates, the cost of capital has been kept consistently low and the load factor, used to convert to mills/Kwhe has been higher than either current or historic levels. As a result, capital costs in mills/ Kwhe reported by the AEC and some companies seeking licenses are too low.

Finally, Section VII relates nuclear power to Project Independence. The aggregate energy output of nuclear reactors is compared with the aggregate direct and indirect energy input required for their construction and operation. The period covered is 1974-1985. The estimate is conservative because waste management, transportation, and fuel cycle costs, other than enrichment, are excluded. Because nuclear generated power must be compared with its alternatives, government funding of research, development, and insurance are discussed in this section.

B. Power Generation Costs

In 1973, the Atomic Energy Commission (AEC) projected 1981 power generation costs at 15.20 mills/kilowatt hour of electricity (Kwhe) for a 1000 MWe light water nuclear reactor.[12] This was the sum of 11.70 mills/Kwhe for capital, 2.50 mills/Kwhe for fuel and 1.00 mills/Kwhe for operation and maintenance. Based on these 1973 estimates and the five percent escalation rate suggested by the AEC, 1980 costs would be 11.57, 2.50 and 0.95 mills/Kwhe respectively; a total of 15.02 mills/Kwhe. The fuel cost used by the AEC for 1981 was that calculated for 1973 and was not escalated. The AEC claimed that nuclear fuel cycle costs, "...will remain constant because of improvements in technology and cost reductions as a result of increases in scale in manufacturing."[13]

For comparison, Table I-2 summarizes the nuclear power generation costs developed in this study. The 1980 costs are projected at 22.11 mills/Kwhe, a difference of more than seven mills/Kwhe over the AEC estimate. The basis for this difference is the methodology and assumptions concerning nuclear plant availability factors, fuel cycle component cost increases, and the method of escalating costs.

The capital costs assumed in the AEC estimate, escalated to 1980, are presented in Table I-3. The influence of the load factor is shown as it is of particular relevance to the cost comparison between nuclear and fossil fuels. Based on AEC estimates, total 1980 capital costs for a 1000 MWe nuclear plant are $608 million or 16.02, 14.87, 13.88, and 13.01 mills/Kwhe for load factors of 65, 70, 75, and 80 percent respectively. These costs include interest, added as an indirect cost at seven percent annually, and escalation due to inflation compounded at seven percent annually.

TABLE I-2

Projected 1980 Generation Costs

for an Average 1000 MWe

Light Water Nuclear Power Plant

(mills/Kwhe)

Cost Component	
Capital	16.02
Fuel	4.97
Operation and Maintenance (O and M)	1.12
Total Generation Costs	22.11

Sources: Tables I-3, III-2, and Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73, p. 15.

Note: The AEC estimated 1973 O and M costs of 0.70 mills/Kwhe, escalating at 7 percent annually results in a 1980 cost of 1.12 mills/Kwhe.

TABLE I-3

Projected 1980 Capital Costs
for an average 1000 MWe
Light Water Reactor Nuclear
Power Plant

Direct Costs	(Millions of Dollars)	(mills/kwhe) Load Factor = .65	(mills/kwhe) Load Factor = .70	(mills/kwhe) Load Factor = .75	(mills/kwhe) Load Factor = .80
Land	1.0				
Structure of Site Facilities	53.2				
Reactor Plant Equipment	80.8				
Turbine Plant Equipment	89.2				
Electric Plant Equipment	30.6				
Miscellaneous Plant Equipment	5.5				
Contingency and Spare Parts Allowance	19.7				
Subtotal (Direct Costs)	280.0				
Indirect Costs					
Professional Services	45.0				
Other Costs	30.0				
Interest During Construction (7 percent/year)	83.0				
Subtotal (Indirect Costs)	158.0				
Total Plant Costs (1973 Dollars)	438.0				
Inflation on the Direct Costs (7 percent/year)	170.0				
Total (1980 dollars)	608.0	16.02	14.87	13.88	13.01

Assumptions:

i) Construction schedule = 7 1/2 years

ii) The environmental assurance equipment includes natural draft cooling towers and a near-zero radwaste system.

iii) Annual fixed charge on capital = 15%

Source: Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73, pp. 12 and 19.

A justification of AEC capital costs has not been made other than to note some of the procedures used to obtain the estimates:

(1) In escalating costs from 1973 to 1980 dollars, the AEC used a method which approximates the summation of simple interest on the direct costs over the construction period.[14] Inflation rates are usually compounded annually. Hence, this method is used in place of the AEC method. Obviously, the AEC procedure leads to lower projected costs.

(2) The AEC states that their estimates include environmental assurance equipment such as natural draft cooling towers and a near-zero radwaste system.[15] The costs of these devices is not made clear. In 1972, capital costs for natural draft cooling towers were estimated by the Atomic Industrial Forum to range from $12 million to $15 million for a 1000 MWe nuclear power plant.[16] A radwaste system that would limit the average annual dose of I^{131} to an individual located offsite to 0.04 mrem/year would cost about $3.5 million.[17]

(3) The AEC assumed a plant construction period of 7½ years. However, a construction period of almost ten years appears to be developing in the industry. The longer construction period increases costs.

(4) The reported capital costs do not include provision for permanent or temporary waste disposal, changes in emergency core cooling or radiation standards, or decommissioning. Inclusion would raise both direct capital costs and contingency reserves.

(5) The cost of land has been set at an arbitrary $1 million. By way of comparison, land costs reported by the Illinois Power Company are about $10 million,[18] and these have been challenged as too low.

(6). In determining costs in mills/Kwhe, an annual fixed charge of 15 percent was used to change total to annual capital costs. Interest rates have increased since 1973; it should be assumed that the fixed charge rate would increase correspondingly. Increasing the annual charge rate by one percent results in a cost increase of about one mill/Kwhe.

Based on an analysis of nuclear power costs made by Arthur D. Little, Inc.,[19] it is possible to derive considerably higher nuclear power electric generation costs. The Arthur D. Little study analyzes the construction of two 1150 MWe nuclear power plants for the Northeast Utilities System. The start-up dates of the two plants are 1981-82 and 1983-84, respectively. The cost estimates of each differ, reflecting expected savings on the second plant in terms of licensing, engineering, and construction costs. Using the methodology and estimates employed for the first plant, the capital costs derived in the present study were revised. In Table I-4 they are

TABLE I-4

Revision of Table I-2 Based on
Arthur D. Little, Inc., Methodology

	(Millions of Dollars)	(mills/Kwhe)(1)
a) Direct Costs (1973 Dollars)	260	
b) Escalation(2)	158	
c) AFDC(3)	100	
Subtotal	518	
d) Use and Sales Taxes(4)	12	
e) Utility Cost(5)	41	
f) Contingency(6)	78	
Total (1980 dollars)	649	17.09(7)

(1) - Load Factor = .65

(2) - 7% annually

(3) - Allowance for funds during construction (proportioned to A. D. Little)

(4) - 7% of equipment and materials costs

(5) - Based on Table I-6

(6) - 15%

(7) - Annual fixed charge on capital = 15%

In Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH 1099, Dec. 1971, p. 94, fixed charge rates on depreciable capital are assumed to include i) recovery of investment, ii) return on investment, iii) all taxes (federal, state and local), iv) interim replacements, and v) property insurance. Total fixed charge rates are calculated as follows:

Weighted average of cost of money	12.70%
Depreciation (sinking fund, 15 years)	2.54%
Federal income tax	5.69%
State and local taxes	2.51%
Interim replacements	0.35%
Property insurance	0.25%
Total fixed charge rate	24.04%

The capital cost shown above, excluding taxes, is $637 million, if the 24.04% fixed charge rate on capital is used to determine costs in terms of mills/Kwhe, a capital cost of 26.89 mills/Kwhe is found.

Sources: Arthur D. Little, Inc., A Study of Base-Load Alternatives for the Northeast Utilities System, July 5, 1973, Table 7, and Table I-3.

shown to be $649 million. Based on a 65 percent availability factor and annual capital cost rate of 15 percent, these costs are 17.09 mills/Kwhe. From the revised capital costs shown in Table I-4 and an annual fixed charge rate on capital of 24.04 percent, a capital cost of 26.89 mills/Kwhe is derived. Assuming that fuel, operation and maintenance costs are those found in Table I-2, 1980 nuclear power electric generation costs could be 32.98 mills/Kwhe. This is shown in Table I-5.

The projected capital costs derived by Arthur D. Little, Inc., can be revised in order to compare them with the AEC estimates discussed above. Table I-6 is the result. Taxes and utility costs have been subtracted from total costs to give a semi-comparative total. Further reduction and additions have been made in order to compare these estimates with the AEC estimates by using equivalent assumptions for interest, escalation, and contingency costs. Total capital costs of $585 million were derived. Table I-3 shows an AEC cost estimate of $608 million.

The state of the art of cost estimation and reporting may be further exemplified by a comparison between estimates provided by the Illinois Power Company, the Union Electric Power Company, and Arthur D. Little, Inc. The first is for a 950 MWe boiling water reactor with a cooling lake, the second for an 1175 MWe pressurized water reactor with natural draft cooling towers, and the third is for an 1150 MWe reactor, apparently without cooling towers. The expected dates of operation and the load factors are similar. The 1980 Union Electric (UE) cost estimate is 21.1 mills/Kwhe at the bus bar. This includes a fuel cost of only 2.23 mills/Kwhe.[20] By contrast, the Illinois Power Company (IPC) estimates the costs at 12.3 mills/Kwhe excluding taxes and 13.9 mills/Kwhe if taxes are included. IPC includes a decommissiong cost of 0.13 mills/Kwhe, which UE does not, and estimates fuel consumption costs at 4.2 mills/Kwhe.[21] Finally, Arthur D. Little,

TABLE I-5

Possible 1980 Generation Costs
1000 MWe Light Water Nuclear Power Plant
(mills/Kwhe)

Cost Component	
Capital	26.89
Fuel	4.97
Operations and Maintenance	1.12
Total Generation Costs	32.98

Sources: Tables I-4 [cf. footnote (7)], and I-2.

TABLE I-6

Revised Authur D. Little, Inc. Capital Costs Applied to an Average 1000 MWe Nuclear Power Plant in 1980(1)

(Millions of Dollars)

	Equipment	Materials	Labor	Row Total
a) Direct Costs (1973 dollars)	124	31	150	306
b) Escalation (2)	42	6	89	137
c) AFDC (3)	42	10	59	110
Subtotal:	208	47	298	553
d) Use and Sales Tax (4)				15
e) Utility Cost (5)				41
f) Contingency (15%)				83
TOTAL (1980 dollars):				692
minus d) and e)				-56
Comparative Total (1980 dollars)				636
minus contingency, escalation, and interest cost differences from those if AEC assumptions were used.(6)				-61 -30 +40
Comparative to AEC Totals (1980 dollars)				585

(1) Estimate relates to the power plant proper, exclusive of site and the required investment in nuclear fuel inventory.

(2) Weighted average = 6.4% on direct costs, simple interest calculation.

(3) Allowance for Funds During Construction, computed at 8% per annum.

(4) Computed at 7% of equipment and materials costs.

(5) Based on data supplied by Northeast Utilities.

(6) AEC computes contingency costs at less than 4%, escalation at 5% annually, and interest at 7% annually. cf: Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73, p. 19.

Source: Arthur D. Little, Inc., A Study of Base Load Alternatives for the Northeast Utilities System, July 5, 1973, Table 7.

Inc., estimates capital costs at 16.52 mills/Kwhe, fuel costs at 3.11 mills/Kwhe, and operation and maintenance at 1.66 mills/Kwhe. The total is 21.29 mills/Kwhe.[22] Given these differences, it is worth looking at capital costs as a whole and some of the components. This is deferred until Section VI.

SECTION I FOOTNOTES

1. Atomic Industrial Forum, Nuclear Industry, March 1973, p. 5.

2. Ibid., April 1974, p. 3.

3. Ibid., March 1973, p. 6.

4. Ibid., November 1973, p. 17.

5. Ibid., September 1973, p. 22.

6. Ibid., February 1974, p. 9.

7. Ibid., March 1974, p. 22.

8. Ibid., March 1973, p. 22.

9. New York Times, December 2, 1973.

10. Atomic Industrial Forum, Op. Cit., April 1974, p. 12.

11. NUS Corporation, Guide for Economic Evaluation of Nuclear Reactor Plant Designs, for the U.S. Atomic Energy Commission, Division of Technical Information, NUS-531, January 1969.

12. Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73, p. 15.

13. Idem. The validity of this contention is discussed at length in Sections III-V.

14. In The Nuclear Industry 1973, the AEC estimated the following cost increases due to inflation during a 7-1/2 year construction period. Direct costs were assumed to range from $257 million to $299 million.

	(Millions of Dollars)
at 4 % inflation	74 - 86
at 5 % inflation	94 - 110
at 6 % inflation	115 - 134
at 7 % inflation	137 - 160
at 8 % inflation	159 - 189

If these rates are calculated using simple interest, the following cost escalation results:

	(Millions of Dollars)
at 4 % inflation	77 - 90
at 5 % inflation	96 - 112
at 6 % inflation	116 - 135
at 7 % inflation	135 - 157
at 8 % inflation	154 - 179

It is not clear that the AEC used a simple escalation rule on direct costs to obtain their estimates, but the number suggest a method approximating simple escalation.

See: Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73, Table 1-5, p. 12.

15. Idem.

16. Atomic Industrial Forum, Op. Cit., September 1972, p. 12.

17. Ibid., May 1972, p. 19.

18. Illinois Power Company, Clinton Power Station 1 and 2, Environmental Report, 1974, Vol. 3, p. 8.2-1.

19. Arthur D. Little, Inc., A Study of Base-Load Alternatives for the Northeast Utilities System, July 5, 1973.

20. H. Clyde Allen, Affidavit before the Public Service Commission of the State of Missouri, Case No. 18,117, September 5, 1974, pp. 9-10, 45.

21. Atomic Energy Commission, Directorate of Licensing, Draft Environmental Statement, related to the proposed Clinton Power Station Units 1 and 2, Illinois Power Company, Docket Nos. 50-461 and 50-462, October 1974, p. 10-8.

22. Arthur D. Little, Inc., Op. Cit., Figure 32.

SECTION II: NUCLEAR POWER FORECASTS AND POWER AVAILABILITY

A. Forecasts

Delays in the completion of nuclear power plants have become a common occurrence. Of 35 plants scheduled to begin operation in the summer of 1973, 30 were delayed.[1] In the previous year, 29 plants did not meet their scheduled deadlines. The Federal Power Commission (FPC) reported that in 1973, 50 of 56 nuclear plants scheduled to begin commercial operation between 1972 and 1973 had experienced some delay during construction. Furthermore, 19 of 36 plants scheduled for operation between 1976 and 1978 had been rescheduled for later start-up dates.[2]

By November, 1973, there were 37 operating reactors in the United States. Five more were expected to be on line by the end of the year. Four more would have been added but for construction problems. Early in 1973, the AEC reviewed 35 pending applications for operating licenses. It was found that 18 reactors had construction delays due to design problems with the rods that hold the fuel and 17 had problems with the location of lines carrying the steam that runs the electric turbines.[3] The Atomic Industrial Forum (AIF) announced that in the short time between September, 1973, and March, 1974, 77 nuclear plants then under construction had their start-up dates delayed from 1 to 13 months each.[4] This represented nearly one-half of the nuclear plants then under construction.

In December, 1973, the AIF made a survey of 95 nuclear power plants under construction or awaiting construction permits.[5] It was found that 70 of the 95 plants had experienced some delay. Of the 47 plants under construction, 46 reported delays ranging from five months to five years.

Twenty-four of the 48 plants waiting for construction permits had experienced delays ranging from two months to five and one-half years. The average delay in both categories was slightly over two years. Measured from the date of order, nuclear plant completion time had increased from eight years to ten years.[6] Whether further delays can be avoided depends on a number of factors. These include: equipment delivery delays and equipment component failures, strikes by both construction labor and equipment manufacturers' employees, rescheduling difficulties, changes in regulatory procedures, prolonged regulatory procedures, legal changes and challenges on both the federal and local level, material shortages, low productivity of labor and the weather.[7]

For the nuclear forecast in this study a five and one-half to six year construction period has been assumed. For plants not yet under construction, an eight year lead time has been assumed. This includes the period from the date of application for a construction permit to the expected date of commercial operation.[8] For plants for which there is not even a reported date of filing for a construction permit, a ten year lead time from the date of order was assumed.

The results are given in Table II-1. It can be seen that new plant completions are expected to continue at a level below 10,000 MWe per year until 1981. Subsequently, plants ordered in 1972 and 1973 are scheduled to begin operation. Table II-1 shows that installed generating capacity at the end of 1973 was about 24,000 MWe. This capacity level is expected to increase to 47,788 MWe by the end of 1975. Plant capacity in 1980 is estimated to be 94,562 MWe. The 1983 estimate was based on present nuclear plant orders and a five and one-half year completion allowance from the date construction is reported to begin. This resulted in an estimate of firm nuclear plant capacity of 173,854 MWe. By including those plants which

TABLE II-1

Projection of Nuclear Plant Capacity[1]
(MWe)

PAD District	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
I: Firm[2]		5267	8022	4015	2055	2733	2120	11932	14918	8078	6000
Other[3]											8150
Cumulative:											
Firm	11980	17247	25269	29284	31339	34072	36192	48124	63042	71120	77120
Other											8150
II: Firm		2200	1054	3175	3133	2250	3105	1184	8960	14770	5500
Other											3862
Cumulative:											
Firm	9373	11573	12627	15802	18935	21185	24290	25474	34434	49204	54704
Other											3862
III: Firm		1968	1978	926	860	-	-	3765	5750	7940	2150
Other											2300
Cumulative:											
Firm	1718	3686	5664	6590	7450	7450	7450	11215	16965	24905	27055
Other											2300
IV: Firm	-	330	-	-	-	-	-	-	-	-	-
Other											
Cumulative:											
Firm	-	330	330	330	330	330	330	330	330	330	330
Other											
V: Firm		913	2190	1156	1100	-	-	2370	-	4466	760
Other											9100
Cumulative:											
Firm	795	1708	3898	5054	6154	6154	6154	8524	8524	12990	13750
Other											9100
Subtotal: Annual											
Firm		10678	13244	9272	8043	4983	5225	19251	29628	35254	14410
Other											23412
Total		10678	13244	9272	8043	4983	5225	19251	29628	35254	37822
Cumulative Total											
Firm	23866	34544	47788	57060	65103	70086	75321	94562	124190	159444	173854
Other											23412
Total	23866		47788					94562			197266

Source: Atomic Industrial Forum, Nuclear Industry.

March 1973, pp. 26-27
December 1973, p. 39
February 1974, pp. 26-27
March 1974, pp. 24-25

(1) The 1973-1983 estimates are based on actual orders for nuclear plants through the year 1973. A ten year lead time for construction completion based on the year of order or an 8 year lead time for construction completion based on the expected year of application for a construction permit (whichever yielded the earliest year of completion) was used when these lead times were not projected by the ordering utility.

The AEC (1972) and AIF (1973) project nuclear capacity to reach 280,000 MWe and 365,000 MWe respectively by 1985. In view of the 1983 firm estimate, if these figures are to be reached, 106 and 191 1000 MWe plants would have to be ordered, respectively, during the years 1974-1975 for installation during 1984 and 1985. With respect to the total estimate, 83 and 168 nuclear plants, respectively, must be ordered during 1974-1975 for installation in the years 1984-1985.

(2) Firm projections are for nuclear plants which are under construction or have been ordered and a specific vendor and site announced.

(3) Other projections include nuclear plants on which options have been taken, only letters of intent have been issued, or no vendor or site has yet been selected.

were announced only by letters of intent or options plus those plants for which no site or vendor was named, the estimate of installed generating capacity was increased for 1983 to 197,266 MWe.

Assuming no further increase in construction delays, Table II-1 indicates that if the Atomic Energy Commission (AEC) nuclear power estimate for 1985 of 280,000 MWe is to be reached, firm commitments for the completion of 106 additional 1000 MWe plants must be made. These plants will have to be operational in 1984-1985. Therefore, they will have to be ordered in 1974-1975. Based on orders published in the journal of the Atomic Industrial Forum, Nuclear Industry, a maximum estimate of cumulative installed nuclear plant generating capacity was made. Table II-2 shows this maximum estimate given the assumption that the trend of plant orders indicated in Table II-3 continues. The estimate assumes that installation rates are maintained near the 1980-1981 rates and are higher than the assumed 1982-1983 rates shown in Table II-3. Nuclear capacity levels in Table II-2 for 1975, 1980 and 1985 are 47,788 MWe, 119,111 MWe and 250,331 MWe, respectively.

The capacity levels projected in Table II-2 differ from those in Table II-1 for the years 1976-1985. The differences are due to the fact that in many cases utilities have projected the completion time of their nuclear plants to be less than eight years from date of order. This is inconsistent with developing trends in the nuclear reactor construction industry, and is reflected in the large difference found in the 1980 projection in this study (Table II-1) compared to the maximum projection (Table II-2) based on a speed up in construction trends. Thus, the projected 1980 capacity level is 94,562 MWe (Table II-1) while the projected maximum is 119,111 MWe (Table II-2). No 1985 nuclear capacity estimate is made in Table II-1 because the 1974 and 1975 nuclear plant orders

TABLE II-2

Maximum Installed Nuclear Plant Generating Capacity: Cumulative
MW(e)

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
PAD District I	11980	17247	25269	29284	32254	37002	46094	56492	67562	73210	87360	97360	107360
PAD District II	9373	11573	12627	15802	18935	21185	26152	34334	43504	50404	59766	64766	69766
PAD District III	1718	3686	5664	6590	7450	8750	12445	16965	19165	24905	29355	34355	39355
PAD District IV	0	330	330	330	330	330	330	330	330	330	330	330	1000
PAD District V	795	1708	3898	5054	6154	6154	7294	10990	12230	12990	22850	27850	32850
Total	23866	34544	47788	57060	65123	73421	92315	119111	142791	161839	199661	224661	250331

Sources: Tables II-5 and II-6. For the 1984-1985 estimate, the extrapolation is based on data in Table II-5.

	1984	1985
PAD District I	10000	10000
PAD District II	5000	5000
PAD District III	5000	5000
PAD District IV	-	770
PAD District V	5000	5000
Total	25000	25770

If the (1972) AEC and (1973) AIF national estimates for 1985 of 280,000 and 365,000 MW(e), respectively, are to be met, yearly additions for 1984-1985 must be:

	1984	1984
AEC	40000	40000
AIF	82500	82500

TABLE II-3

Total Plant Capacity Ordered or Under Construction by March 1974 by PAD District and Year of Intended Installation*
MW(e)

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
PAD District I	5267	8022	4015	2970	4748	9092	10398	11070	5648	14150
PAD District II	2200	1054	3175	3133	2250	4967	8182	9170	6900	9362
PAD District III	1968	1978	926	860	1300	3695	4520	2200	5740	4450
PAD District IV	330	-	-	-	-	-	-	-	-	-
PAD District V	913	2190	1156	1100	-	1140	3696	1240	760	9860
Total	10678	13244	9272	8063	8298	18894	26796	22630	19048	37822
Cumulative (from 1974)		23922					96145			175645

*Includes plants for which no site has been announced, have been designated only by letters of intent, are options, or for which no vendor has been announced.

Source: See Table II-4.

are not known. Therefore, a complete inter-tabular comparison is not possible.

If the conditions assumed in Table II-1 are met, nuclear plant additions will be less than 10,000 MWe per year through 1979. After that, a surge of plant additions will occur. In 1982, capacity additions will be 35,254 MWe. An additional capacity of 37,822 MWe will be added in 1983. This may produce a bottleneck in construction, given the type of labor and material needed for the completion of certain high technology operations.

Tables II-3 and II-4 show nuclear plant capacity additions based on AIF data. Table II-3 includes not only firm plant orders, but also orders for plants based only on letters of intent, on options, or plants for which no vendor or site has been selected. Table II-4 includes only firm plant orders and plants already under construction. If schedules are met, in 1980 almost 27,000 MWe of plant capacity will be installed. By March, 1974, nuclear plant capacity of 51,972 MWe to be installed through 1980 was under construction. Table II-5 shows the yearly installation rate.

If administrative and regulatory delays are eliminated, operational lead times depend on construction time. Figures II-2, 3, and 4 are graphed projections of construction expectations for nuclear plants (capacity and number) due to be in operation prior to 1986. Figure II-2 is a projection of the nuclear capacity presently contracted to be concurrently under construction. The annual projected levels of plant construction fall below the contracted levels yearly through 1978 due to methodological differences. All utilities which have announced the intention of constructing a nuclear facility have established a commercial operating goal date. This inevitably means that some nuclear plants are scheduled to be under construction for only three years while others are sched-

TABLE II-4

Firm Plant Capacity Orders* and Capacity Under Construction
by PAD District by Year of Intended Installation
MW(e)

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
PAD District I	5267	8022	4015	2970	4748	9092	10398	11070	5648	6000
PAD District II	2200	1054	3175	3133	2250	4967	8182	9170	6900	5500
PAD District III	1968	1978	926	860	1300	3695	4520	2200	5740	2150
PAD District IV	330	-	-	-	-	-	-	-	-	-
PAD District V	913	2190	1156	1100	-	1140	3696	1240	760	760
Total	10678	13244	9272	8063	8298	18894	26796	22630	19048	14410
Cumulative (from 1974)		23922					96145			152233

*Plants which have been ordered for known sites and vendors.

Sources: Tables II-3 and II-4.

Atomic Industrial Forum, Nuclear Industry.

March 1973, pp. 26-27
Dec. 1973, p. 39
Feb. 1974, pp. 26-27
March 1974, pp. 24-25

TABLE II-5

Plant Capacity Under Construction by
March, 1974, by Completion Date
MW(e)

	1974	1975	1976	1977	1978	1979	1980	1981
PAD District I	5267	8022	4015	2055	2733	2120	-	1050
PAD District II	2200	1054	3175	3133	2250	3105	527	-
PAD District III	1968	1978	926	860	-	-	-	-
PAD District IV	330	-	-	-	-	-	-	-
PAD District V	913	2190	1156	1100	-	-	-	-
Total	10678	13244	9272	7148	4983	5225	527	1050
Cumulative		23922					51077	

Source: Atomic Industrial Forum, Nuclear Industry, March, 1974, pp. 24-25.

uled for up to nine years of actual construction time. These construction periods represent the contracted time span. The projected nuclear construction levels by year are based strictly on a six year plant construction time. This means that some utilities planned on filing construction permit applications in 1974 to begin construction in 1976 for plants not projected to begin construction in 1976. Instead, they were projected to begin construction six years prior to their expected start-up date. Therefore, under the methodology used for the projection, a utility which had announced its intention of filing a construction permit in 1974 for a plant ordered in 1973, and expecting commercial operations in 1983, was not projected to begin construction until 1978.

Projections of both nuclear capacity and the number of plants concurrently under construction by year are shown in Figure II-2. Figure II-3 shows the contracted nuclear capacity total for concurrent construction for the years 1974 through 1984.

The projection in Figure II-3 is based on a six year construction lead time with respect to the installed nuclear generating capacity forecast in Table II-1 for the period 1974 through 1983 and Table II-2 for 1984 and 1985.

In Figure II-4, all nuclear plants shown for which the construction period begins before 1977 are based on actual orders made prior to 1974. The completion dates were specified. The initial construction dates were determined by allowing a three year period from the date of order or a one and one-half year period from the anticipated application date for a construction permit. This led to construction periods ranging from three to nine years with an average period of five to six years.

Allowing some relaxation of the strictness of the projected estimates with respect to construction lead times and

the possibility of some delays in contracted construction, a median level of total yearly plant construction between the contracted and projected levels should be expected through 1977. Subsequently, differences in contracted and projected capacity must be made up through increased commitments. Even an annual linear increase in total concurrent nuclear plant construction from 1974 on, would result in significant demands on skilled labor, materials, components and equipment. With current shortages in these areas,[9] a construction crisis in the future does not appear unreasonable.

In addition to domestic orders, U.S. vendors are supplying components, systems, and engineering manpower for foreign contracts. This may add to potential U.S. construction bottlenecks. Tables II-6 and II-7 relate to foreign commitments of American suppliers. Table II-6 shows which countries ordered plants from U.S. suppliers during the years 1972 and 1973. Japan, a heavy buyer of U.S. reactors, did not place any orders in 1972 and 1973. A listing of earlier Japanese construction contracts with U.S. vendors is given in Table II-7. Suppliers listed with a slash (e.g., W/) are building the nuclear reactor jointly with a Japanese company.

As a result of construction and other delays, the AEC has reduced its 1972 forecast of about 151,000 MWe by 1980. Its 1973 estimate was only 132,000 MWe. By March, 1974, it was expected that a new estimate for 1980 would be around 100,000 MWe.[10] This is close to the projection developed in this study. Given the delays, the completion time for a nuclear power plant is about 25 percent longer than for a fossil fuel plant.

Both the AEC estimates and those presented in this paper may be overly optimistic. The recent rash of planned nuclear power plant delays and curtailments due to financing problems and utility re-evaluations of projected demand post-

TABLE II-6

Foreign Orders 1972 and 1973

Country	1972 order	1973 order	Expected Installation Date 1977	1978	1979	Plant Size MW(e)	NSSS Supplier
Spain	X		X			900	W
	X			X		900	W
	X			X		900	W
		X	X			957	GE
Mexico	X		X			660	GE
		X		X		660	GE
Switzerland	X			X		940	GE
Yugoslavia		X		X		615	W
W. Germany	X				X	660	GE
Sweden	X				X	900	GE
Taiwan	X				X	900	GE
	X				X	900	GE
Total						9892	

Source: Atomic Industrial Forum, <u>Nuclear Industry</u>.

Nov. - Dec. 1972, p. 9
Dec. 1973, p. 40

TABLE II-7

Japanese Reactors Built or Being Built, Supplied by U.S. Vendors (1973)

	Start of Construction	MWe (net ultimate)	Supplier
Kansai (Ohii - 2)	1972	1175	W/
Kansai (Ohii - 1)	1972	1175	W/
JAPC (Tokai - 2)	1972	1100	W/
Tokyo (Fukushima - 6)	1971	1100	GE
Kansai (Takahama - 1)	1969	826	W/
Tokyo (Fukushima - 2)	1968	784	GE
Tokyo (Fukushima - 1)	1966	460	GE
Kansai (Mihama - 1)	1966	340	W
JAPC (Tsuruga - 1)	1966	357	GE
Total		7317	

Source: Atomic Industrial Forum, Nuclear Industry, May 1973, p. 40.

date the AEC forecasts and have not been accounted for in any of the tables presented in this study.

B. Plant Availability

The amount of nuclear power available depends not only on plant capacity but upon plant availability as well. The latter has been the subject of some controversy. A summary of nuclear plant availability through August, 1973, is given in Table II-8. The total population of 35 plants was evaluated. Of these, 18 had an average plant factor (availability) of 60.9 percent from start-up through October, 1972. Subsequently, quarterly ratings were made. These plant factors ranged from 66.3 to 72.9 percent.

Using quarterly data, of the 35 plants considered, plant factor data existed for 29 plants with 24 having data for the first two quarters of 1973. In the first quarter, eleven plants were available for less than 60 percent of the time; one plant was available between 60 and 70 percent of the time; five plants were available between 70 and 80 percent; and seven plants had factors above 80 percent. In the second quarter, five plants were available less than 60 percent of the time, three plants were available between 60 and 70 percent, five plants between 70 and 80 percent, and eleven plants had factors over 80 percent. These plants had been in operation at least one full quarter. Two new plants were rated between 60 and 70 percent and 70 to 80 percent availability, respectively. These amounted to the total of new additions and yielded a high plant factor level for this quarter.

In the future, as new plants are added at an increasing rate to the availability ratings, the trend will be downward because initial start-up rates have been historically closer to 60 percent availability than to 80 percent avail-

TABLE II-8

Weighted Plant Factors: Startup Through March 31, 1974

PAD Distric: I

Plant	NSSS	Startup	Plant Size (MWe) net	-to 9/30/72	10/1 to 12/31/72	1/1 to 4/30/73	5/1 to 8/31/73	9/1 to 12/31/73	1/1 to 3/31/74
Penn (S1)		-/57	90						
Mass. (Y)	W	2/61	175	.726	.215	.17	.988	.984	.98
NY (IP1)	B&W	10/62	265	.477	.80	0	0	0	.664
Conn. (CY)	W	1/68	575	.772	.97	.981	.431	.11	.89
NJ (OC)	GE	12/69	640	.713	.93	.764	.66	.768	.848
NY (NMP1)	GE	12/69	620	.493	.91[1]	.765[1]	.617	.78	.98
NY (G)	W	7/70	490	.775	.63[1]	.989[1]	.93	.934[6]	0
Conn. (MP1)	GE	3/71	652	.792	0	.261[2]	.256	.836[6]	.95[6]
SC (HBR2)	W	3/71	700	.655	.92	.544[2]	.817	.889	.981
Florida (TP4)	W	9/72	725				.66	.82	.64
Virginia (S1)	W	9/72	820		.53	.63	.79	.453	.164
Vermont (VY)	GE	11/72	540		.72	.49[3]	.885[3]	.481	.881
Florida (TP3)	W	12/72	725			.750[3]	-[3]	.79	.837
Maine (MY)	C-E	12/72	855		-[2]	.799	.721	.838	.951
Mass. (P1)	GE	12/72	655		.686	.897[4]	.859	.837	0
Virginia (S2)	W	5/73	820			.43[4]	.75[5]	.794	.992
SC (O1)	B&W	7/73	886				.737[5]	.737	.747
NY (IP2)	W	-/73	873					.35	.132
Total			11106	.683	.684	.649	.687	.682	.657

[1] Plant operation restricted to 83% of full power

[2] Plant operation restricted to 75% of full power

[3] Plant operation restricted to 93% of full power

[4] Plant operation restricted to 92% of full power

[5] Plant operation restricted to 95% of full power

[6] Plant operation restricted to 85% of full power

TABLE II-8 (Cont.)

Weighted Plant Factors: Startup Through March 31, 1974

PAD District II

Plant	NSSS	Startup	Plant Size (MWe) net	-to 9/30/72	10/1 to 12/31/72	1/1 to 4/30/73	5/1 to 8/31/73	9/1 to 12/31/73	1/1 to 3/31/74
Illinois (D1)	GE	8/60	200	.555	.616	.922	.949	.312	0
Mich. (BRP)		11/62	70	.513					
Illinois (D2)	GE	8/70	809	.419	.606	.857	.854	.921	.749
Wisc. (PB1)	W	12/70	497	.840	0	.463	.953	.95	.997
Wisc. (G2)	/AEC	-/71	53						
Minn. (M)	GE	6/71	545	.652	.925	.51	.755	.902	.784
Illinois (D3)	GE	10/71	809	.584	.911 (1)	.53	.616	.922	.881
Mich. (P)	C-E	12/71	800	.241	.73	.579	.734	0	0
Illinois (QC1)	GE	8/72	809		.84	.85	.84	.86	.88
Illinois (QC2)	GE	8/72	809		.70 (2)	.77	.86	.91	.86
Wisc. (PB2)	W	3/73	497		.89	.463	.95	.998	1.00 (1)
Illinois (Z1)	GE	-/73	1100					.486	0
Illinois (Z2)	GE	-/73	1100						.344
Nebr. (Ft. C)	C-E	-/73	475					.903	.749
Total			7473	.516	.715	.661	.814	.736	.633

(1) Plant operation restricted to 85% of full power

(2) Plant operation restricted to 20% of full power

TABLE II-8 (Cont.)

Weighted Plant Factors: Startup Through March 31, 1974

PAD Districts III, IV and V

Plant	NSSS	Startup	Plant Size (MWe) net	- to 9/30/72	10/1 to 12/31/72	1/1 to 4/30/73	5/1 to 8/31/73	9/1 to 12/31/73	1/1 to 3/31/74
PAD District III									
Ala (BF1)	GE	-/73	1718						
PAD District IV									
				(NONE)					
PAD District V									
Calif. (HB)		8/63	65(1)	.629					
Wash. (H)	/AEC	12/66	300(1)	.409					
Calif. (SO)	W	1/68	430	.717	.930	.960	.521	.41	.76
Total			795	.594					

(1) maximum rated name plate capacity

TABLE II-8 (Cont.)

Weighted Plant Factors: Startup Through March 31, 1974

Totals

Plant	Total (MWe (net)	- to 9/30/72	10/1 to 12/31/72	1/1 to 4/30/73	5/1 to 8/31/73	9/1 to 12/31/73	1/1 to 3/31/74
Totals							
PAD District I	11106	.683	.684	.649	.687	.682	.657
PAD District II	7473	.516	.715	.661	.814	.736	.633
PAD District III	1718						
PAD District IV	-						
PAD District V	795	.594	.930	.960	.521	.41	.76
Total	21092	.609	.682	.663	.729	.697	.649

Source: Atomic Industrial Forum, Nuclear Industry.
Nov.-Dec. 1972, p. 21
Feb. 1973, pp. 32-33
June 1973, pp. 22-23
Oct. 1973, pp. 24-25

ability. The new plants will weight the average more than the debugged older plants.

For comparison with an AEC publication[11] containing nuclear operating statistics for 1972, a similar compilation using AIF data was made. The AIF data are presented in Table II-9. The AEC figures are given in Table II-10. The AIF statistics involve 20 plants for the period from February 1 to December 31, 1972. The AEC statistics include 19 plants for all of 1972. The AEC includes only those nuclear plants that had been operating for at least three months during 1972. The AEC study did not include those plants which began operation after August, 1972. As a result, they estimated plant factors slightly higher than would be expected if these newer plants were included. In both tables the plant availability factor is measured as the percent of total possible time that a plant was actually producing electricity. That is, the plant factor is equal to generating time divided by total time during the period. Stand-by time was not included in the generating time figure.

Table II-9 shows that the 20 plants included in the AIF study generated electricity for a total of 102,237 out of 142,741 possible hours for an average plant factor of 71.6 percent. On a weighted scale, using plant capacity as the weight, the 20 plants accounted for 8221 MWe of electricity generation out of a possible installed generating capacity of 11,682 MWe for a weighted plant factor of 70.4 percent. The AEC (Table II-10) estimated plant factors for the 19 plants at 73.4 percent unweighted and 73.3 percent weighted. It should be noted that all three availability ratings (Tables II-8, 9, and 10) are significantly below the 80 percent used in most publications for the estimation of power costs and sales.

The differences between the AEC and the AIF results are probably due to alternative data bases. The methodology

TABLE II-9

Plant Factors for Plants in Operation February 1 - December 31, 1972

Plant	NSSS	Start Up	Plant Size MWe (net)	Total clock time (Hrs)	Total Time Generator on Line (Hrs)	Plant Factor	Operation Availability MWe
				/PAD District I/			
Mass (Y)	W	2/61	175	8039	3819	.475	83
Y (IP1)	BCW	10/62	265	8039	5728	.712	189
Conn (CY)	W	1/68	575	8039	6978	.868	499
NJ (OC)	GE	12/69	640	8039	6475	.805	515
NY (NMP1)	GE	12/69	620	8039	5520	.687	426
NY (RE. G)	W	7/70	490	8039	5290	.658	322
Conn (MP1)	GE	3/71	652	8039	4439	.552	360
SC (HBR2)	W	3/71	700	8039	6802	.846	592
Virginia (S1)	W	9/72	820	2208	1170	.530	435
Vermont (VY)	GE	11/72	540	2649	1970	.744	402
Total				71377	49706	.696	
Weighted Total			5477			.698	3823
				/PAD District II/			
Illinois (D1)	GE	8/60	200	8039	6866	.854	171
Illinois (D2)	GE	8/70	809	8039	4492	.559	452
Wisc. (PB1)	W	12/70	497	8039	5809	.723	359
Minn. (M)	GE	6/71	545	8039	6993	.870	474
Illinois (D3)	GE	10/71	809	8039	6985	.869	703
Mich. (P)	C-E	12/71	800	7200	4500	.625	500
Illinois (QC1)	GE	8/72	809	6756	4935	.731	591
Illinois (QC2)	GE	8/72	809	5502	2805	.510	413
Wisc. (PB2)	W	3/73	497	3672	2997	.816	406
Total				63325	46382	.732	
Weighted Total			5775			.705	4069
				/PAD District V/			
Calif. (SO)	W	1/68	430	8039	6149	.765	329
				TOTAL			
Unweighted Total				142741	102237	.716	
Weighted Total			11682			.704	8221

Sources: Atomic Industrial Forum, Nuclear Industry.

June, 1972, p. 39
October, 1972, p. 33
February , 1973, p. 53

TABLE II-10

AEC Plant Factors for Plants in Operation January 1 - December 31, 1972

Plant	NSSS	Start Up	Plant Size MWe (net)	Total clock time (hrs)	Total Time Generator on Line (hrs)	Plant Factor	Operation Availability MWe
				PAD District I			
Mass (Y)	W	2/61	175	8784	4565	.520	91
Y (IP1)	BCW	10/62	265	8784	5878	.669	177
Conn (CY)	W	1/68	575	8784	7702	.877	504
NJ (OC)	GE	12/69	640	8784	7097	.808	517
NY (NMP1)	GE	12/69	620	8784	6167	.703	436
NY (RE. G)	W	7/70	490	8784	6030	.687	337
Conn (MP1)	GE	3/71	652	8784	5183	.591	385
SC (HBR2)	W	3/71	700	8784	7483	.852	596
Total				70272	50105	.713	
Weighted Total			4117			.739	3043
				PAD District II			
Illinois (D1)	GE	8/60	200	8784	6968	.782	156
Illinois (D2)	GE	8/70	809	8784	5241	.596	482
Wisc. (PB1)	W	12/70	497	8784	6349	.723	359
Minn. (M)	GE	6/71	545	8784	6977	.794	433
Illinois (D3)	GE	10/71	809	8784	7548	.860	696
Mich. (P)	C-E	12/71	800	4416	3142	.712	570
Illinois (QC1)	GE	8/72	809	4416	3535	.802	649
Illinois (QC2)	GE	8/72	809	4416	2350	.532	430
Wisc. (PB2)	W	3/73	497	3612	2975	.823	409
Total				60780	45085	.742	
Weighted Total			5775			.725	4184
				PAD District V			
Calif. (HB)		8/63	65	8784	7296	.831	54
Calif. (SO)		1/68	430	8784	6819	.776	334
Total				17568	14115	.803	
Weighted Total			495			.784	388
Unweighted Total				148621	109204	.734	
Weighted Total			10387			.733	7615

Source:

Wilson, T. B., et al, Atomic Energy Commission, Office of Operations Evaluation, Evaluation of Nuclear Power Plant Availability, Jan. 1974, p. 4.

TABLE II-11

Plant Identification for Tables II-8, 9 and 10

PAD District I	
Penn (S1)	Shippingport 1
Mass (Y)	Yankee
NY (IP1)	Indian Point1
Conn (CY)	Connecticut Yankee
NJ (OC)	Oyster Creek
NY (NMP1)	Nine Mine Point 1
NY (G)	R. E. Ginna
Conn (MP1)	Millstone Point 1
SC (HBR2)	H. B. Robinson 2
Florida (TP4)	Turkey Point 4
Virginia (S1)	Surry 1
Vermont (VY)	Vermont Yankee
Florida (TP3)	Turkey Point 3
Maine (MY)	Maine Yankee
Mass (P1)	Pilgrim 1
Virginia (S2)	Surry 2
SC (O1)	Oconee 1
NY (IP2)	Indian Point 2
PAD District II	
Illinois (D1)	Dresden 1
Mich. (BRP)	Big Rock Point
Illinois (D2)	Dresden 2
Wisc. (PB1)	Point Beach 1
Wisc. (G2)	Genoa 2
Minn. (M)	Monticello
Illinois (D3)	Dresden 3
Mich. (P)	Palisades
Illinois (QC1)	Quad Cities 1
Illinois (QC2)	Quad Cities 2
Wisc. (PB2)	Point Beach 2
Illinois (Z1)	Zion 1
Illinois (Z2)	Zion 2
Nebr. (Ft. C)	Ft. Calhoun
PAD District III	
Ala (BF1)	Browns Ferry 1
PAD District IV	
Calif. (HB)	Humbolt Bay
Wash (H)	Hanford
Calif. (SO)	San Onofre

used in this study was the same as that used by the AEC. That is, outage time, both forced and scheduled, was subtracted from the total available plant operating time to obtain generating time. Forced outages were considered as immediate plant removals from service due to a malfunction of component, structure, or system. Scheduled outages were preplanned removals of a plant from service for inspection, refueling, maintenance and general overhaul. Standby status was included as a scheduled outage. Partial outages, resulting from component failures, were not included nor were temporary restrictions on plant capacities considered. Therefore, plant factors are statistically biased upward.

It should be noted that there is a difference between the plant availability factor and the plant capacity factor. The former is the percent of the total time in a given period that a plant or unit was producing electricity. It is equal to the time the generator was on line divided by the total time during the period. The capacity factor is the percent of the total electrical energy actually produced by a plant or unit during the period compared to the energy it might have produced had it operated at the licensed design power level for the entire period. It is equal to the electrical megawatt hours actually produced during the period divided by the product of the licensed design power level (MWe) times the number of hours in the reporting period.

Testimony by D. D. Comey indicates that the unweighted average capacity factor for commercially operating nuclear power plants over 100 MWe has been 54.0 percent from start-up to June 30, 1974. It was 57.3 percent in 1973, and 50.4 percent for the first six months of 1974. He further shows that average capacity factors generally rise through the first four years of operation and decline with increasing age of the plant thereafter. This last conclusion is based on very small

samples in each age group and does not appear to consider recent advances in reactor types. His data are based on the AEC report, Nuclear Power Plant Availability and Capacity Statistics for 1973, (May, 1974) with 1974 data compiled from data supplied by the AEC, Office of Operation Evaluations. Unfortunately, the Comey report does not provide sufficient methodology for checking.[12]

SECTION II APPENDIX: AEC FORECASTS

The basic methodology for the supply projections of nuclear power made in this study is akin to counting. Construction starts, progress, orders, options, and letters of intent are all known. There may be some disagreement concerning assumed time periods, but the range of the disagreements will be small. AEC forecasts, however, appear to be based on an hypothesized quasi-exponential demand curve for electricity. Apparently, it is assumed that supply will grow at the same rate and that nuclear power will get a given rising share of the augmented demand. The AEC position with respect to demand is characteristically stated in the following excerpt:

> The planning of additional generating capacity must be based on estimates of future peak demand for power and energy consumption. Because of the long lead times for base-load plants (4 to 6 years for fossil-fueled, 7 to 10 for nuclear), corresponding long-term forecasts of demand and consumptions are required.
>
> Historically, both the peak and average consumption of electric power have tended to increase exponentially with time, i.e., with about the same percentage increase each year. The most common approach to long-term forecasting has been to assume continued exponential growth, estimating the growth rate from historical data. Refinements have generally involved breaking down total demand (or consumption) into components of use such as residential, commercial, industrial and carrying out the growth-rate determination separately for each component. The assumption of exponential growth may also be modified for one or another component because of other information. For example, the increasing popularity of air conditioning has contributed substantially to growth of residential and commercial consumption during the past 20 years. As the saturation of air conditioning (percentage of actual use divided by potential total use) approaches 100%, this contribution to growing consumption will become small. If reasonable estimates of

> future saturation can be made, it may be appropriate to reduce the estimated future growth constants correspondingly.
>
> A number of academic economists have attempted to relate consumption of electric energy to other socio-econometric variables such as "real" price (price relative to some index of general price level) of electricity and of fuels, population, per capita real income, etc. With respect to long-term forecasting, even a totally satisfactory econometric model of this sort would only transform the problem to that of forecasting values of the supposed explanatory variables. These input forecasts would require the same assumption of historical regularity continuing into the future that is made in the more direct techniques described above.
>
> The staff belief is that the most that is possible is the preparation of reasonable projections based on the available information. Quasi-exponential growth of electricity consumption has persisted over many decades and it is reasonable to assume that it will persist for the next decade.(13)

The primary difficulty with this type of forecasting, one which requires a constant revision of the estimates as the future approaches the present, is that the projection of, say, a reasonable nine percent growth rate over the next ten years based on past data becomes absurd if carried on for a further twenty-five or thirty years. To argue that this is not what was intended is to negate the basis of the AEC argument from the very beginning.

In forecasting, history merely establishes the initial conditions, not the future. Alternatively stated, it is quite plausible that an AEC forecaster, twenty years in the future, will look back at his past and establish the initial conditions, not on an exponential, but on a logistic curve. At the present time it is commonplace to estimate future demand along an exponential curve while supply is estimated along a

logistic or Gompertz curve. The result is an intersection in a year of crisis.

It is possible to show that given an exponential curve, both a logistic and a Gompertz curve can be grafted on to it such that the curves are smoothly continuous and, for a given future date, the curves pass through a wide range of possible demand levels. In other words, we may within a wide margin pick our own personal year of crisis.

A demonstration of this for both a logistic and a Gompertz curve follows. It must be noted that these are purely mathematical. If the exponential curve, which provides the root of the graft, is only statistically determined, more freedom exists.

The equation of the logistic curve is:

$$y = \frac{b}{1 + ae^{-\rho t}}$$

Given a point (t_o, y_o) $y_o > 0$, a slope $m > 0$, and a number $\gamma > 0$ it is possible to find a logistic curve passing through the given point with the slope m and whose critical point has t - coordinate $t_o + \gamma$. The calculations are as follows:

$$\frac{dy}{dt} = \frac{ab\rho e^{-\rho t}}{(1 + ae^{-\rho t})^2}$$

$$\frac{d^2y}{dt^2} = \frac{ab\rho^2 e^{-\rho t}(ae^{-\rho t} - 1)}{(1 + ae^{-\rho t})^3}$$

The critical point occurs where: $\frac{d^2y}{dt^2} = 0$. I.e., $ae^{-\rho t} = 1$,

$$t = \frac{1}{\rho} \log a.$$

The equations we have for determining the parameters a, b, ρ are:

$$(1) \qquad y_o = \frac{b}{1 + ae^{-\rho t_o}}$$

$$(2) \qquad m = \frac{ab\rho e^{-\rho t_o}}{(1 + ae^{-\rho t_o})^2}$$

$$(3) \qquad t_o + \gamma = \frac{1}{\rho} \log a$$

The solutions of the equations are:

From (3) we obtain,

$$(4) \qquad a = e^{\rho(t_o + \gamma)}$$

Substituting this into (2),

$$m = \frac{e^{\rho(t_o + \gamma)} b\rho e^{-\rho t_o}}{(1 + e^{\rho(t_o + \gamma)} e^{-\rho t_o})^2}$$

$$= \frac{b\rho e^{\rho\gamma}}{(1 + e^{\rho\gamma})^2}$$

so, (5) $$b = \frac{m(1 + e^{\rho\gamma})^2}{\rho e^{\rho\gamma}}$$

Using (1), $$y_o = \frac{\dfrac{m(1 + e^{\rho\gamma})^2}{\rho e^{\rho\gamma}}}{1 + e^{\rho(t_o + \gamma)} e^{-\rho t_o}}$$

$$= \frac{m(1 + e^{\rho\gamma})^2}{\rho e^{\rho\gamma}(1 + e^{\rho\gamma})} = \frac{m(1 + e^{\rho\gamma})}{\rho e^{\rho\gamma}}$$

We must solve for ρ:

$$m(1 + e^{\rho\gamma}) = \rho e^{\rho\gamma} y_o$$

$$\rho e^{\rho\gamma} - \frac{me^{\rho\gamma}}{y_o} = \frac{m}{y_o}$$

or,

$$e^{\rho\gamma} = \frac{m}{y_o} \frac{1}{(\rho - \frac{m}{y_o})}$$

$$e^{\rho\gamma}(\rho - \frac{m}{y_o}) = \frac{m}{y_o}$$

The function $e^{\rho\gamma}(\rho - \frac{m}{y_o})$ for $\gamma > 0$ is zero at $\rho = \frac{m}{y_o}$, increases to ∞ as $\rho \to \infty$, and is continuous. Therefore, it takes on the value $\frac{m}{y_o}$ at some value $\rho = \rho_o$. Now from equations (4) and (5) we can determine a and b. Clearly these are the desired parameters.

GOMPERTZ CURVE

The equation of the Gompertz curve is:

$$y = ca^{R^t} \quad \text{where} \quad \begin{array}{l} 0 < R < 1 \\ 0 < a < 1 \end{array}$$

Given a point (t_o, y_o), a slope m, and a number γ, with t_o, y_o, m, γ all strictly greater than 0, we can determine c, a, and R so that the corresponding Gompertz curve passes through (t_o, y_o) with slope m and has its critical point at $t = t_o + \gamma$.

The calculations are:

$$y = ca^{R^t}$$

$$\frac{dy}{dt} = c(\log a)(\log R)R^t a^{R^t}$$

$$\frac{d^2y}{dt^2} = c(\log a)(\log R)^2 R^t a^{R^t}[1 + (\log a)R^t]$$

The critical point is at: $t = \dfrac{-\log(-\log a)}{\log R}$

The equations for a,c, and R are then:

(1) $$y_o = ca^{R^{t_o}}$$

(2) $$m = ca^{R^{t_o}}R^{t_o}(\log R)(\log a)$$

(3) $$t_o + \gamma = \frac{-\log(-\log a)}{\log R}$$

Solving:

From (3), $$(t_o + \gamma)\log R = -\log(-\log a)$$

so, (4) $$\log a = -e^{-(t_o + \gamma)\log R}$$

Substituting this and (1) into (2):

$$m = y_o R^{t_o}(\log R)[-e^{-(t_o + \gamma)\log R}]$$

$$= y_o(R^{t_o})[(\log R)(-R^{-(t_o + \gamma)})]$$

$$= -y_o (\log R) R^{-\gamma}$$

or, $$R^{\gamma} = \left(-\frac{y_o}{m}\right) \log R \quad \text{where} \quad \gamma > 0$$

For $0 < R < 1$, $\log R$ takes on all values in the open interval $(-\infty, o)$ so with $y_o > 0$, $m > 0$, $\left(-\frac{y_o}{m}\right) \log R$ monotonely takes on all values in the interval $(0, \infty)$. Furthermore, for $0 < R < 1$, $\gamma > 0$, R^{γ} monotonely takes on all values in $(0,1)$. Since these are both continuous functions, they must be equal for some value of R, say R_o, with $0 < R_o < 1$.

The value of "a" can now be determined from (4). In fact,

$$a = e^{-e^{-(t_o + \gamma)\log R}}$$

It is clear that $0 < a < 1$ since,

$$-e^{-(t_o + \gamma)\log R} < 0$$

Finally, from (1),

$$y_o = ca^{R^{t_o}}$$

so that, $$c = y_o a^{-R^{t_o}}$$

SECTION II FOOTNOTES

1. Atomic Industrial Forum, Nuclear Industry, March 1973, p. 22.
2. Ibid., p. 23.
3. Wall Street Journal, November 9, 1973.
4. Atomic Industrial Forum, Op. Cit., March 1974, p. 22.
5. Atomic Industrial Forum, Op. Cit., April 1974, pp. 12-13.
6. AIF has reported that "...of 14 nuclear units totalling 11,043 MWe that were not available in June, 1972, but are expected to be available at full or partial capacity this summer (1974), the average length of delay is 22 months." Atomic Industrial Forum, Nuclear Industry, April 1974, p. 12.
7. Atomic Industrial Forum, Op. Cit., p. 22.
8. For confirmation see: Arthur D. Little, Inc., A Study of Base Load Alternatives for the Northeast Utility System, July 1973, Figure 17.
9. Atomic Industrial Forum, Op. Cit., April 1974, pp. 12-13.
10. Wall Street Journal, March 12, 1974.
11. T. R. Wilson, et al, Atomic Energy Commission, Office of Operations Evaluation, Evaluation of Nuclear Power Plant Availability, Jan. 1974.
12. D. D. Comey, "Nuclear Power Plant Reliability," testimony presented at the hearing on Nuclear Power and Advanced Energy Systems, Chicago, September 10, 1974.
13. Atomic Energy Commission, Directorate of Licensing, Draft Environmental Statement related to the proposed Clinton Power Station Units 1 and 2 of the Illinois Power Company, Docket Nos. 50-461 and 50-462, p. 8-6, Section 8.3.1.

SECTION III: FUEL CYCLE COSTS

An analysis of nuclear fuel cycle costs is necessary due to wide variation among estimates made by the Atomic Energy Commission (AEC), the National Petroleum Council (NPC) and others. Calculations made by these organizations and others are based on different cost estimates or noncomparable assumptions. Further, a simple and direct methodology is not presented with the cost estimates. Table III-1 shows how wide are the differences in cost estimates among the AEC, the NPC, AEC Commissioner Larson and Holdren. Nowhere was there a detailed explanation of how their estimates were calculated. A quantitative study was not presented. The current study is an effort to put the methodology for calculating nuclear fuel cycle costs on a consistent and comprehensible basis. It is also an attempt to measure these costs under several different conditions. The present study is an attempt to evaluate the fuel cycle costs that can be expected in the nuclear power industry in the 1980's on a consistent basis.

Between exploration and burnup in a light water nuclear plant, uranium must be mined, milled, prepared (converted), enriched, processed and fabricated. Each step involves a cost, the most expensive of which are mining-milling and the enrichment process. Once the enriched uranium is used in a nuclear plant additional costs due to waste management or recycling of the spent fuel arise. Finally, fuel inventory charges must be accounted for. Together, these costs make up the nuclear fuel cycle costs. Costs due to safeguarding the fuel and insurance liability are considered separately.

The projected fuel cycle costs, in 1980 dollars, for a typical light water nuclear power plant are given in Table III-2. These costs were derived from Table III-3 by using a seven percent annual rate of inflation on the most likely cost estimates. These are shown in the first row of each cost com-

TABLE III-1

A Comparison of Fuel Cycle Cost Estimates
for a 1000 MWe Light Water Reactor

[mills/kWhe]

Fuel Cycle Component	Tails Assay	Cost	AEC[1] (1973 dollars)	AEC[PWR][2] (1967 dollars)	NPC[PWR][3] (1970 dollars)	Holdren[4]	Larson[5]
a) Mining and Milling U_3O_8		\$8/lb U_3O_8			0.66	0.4	0.55
		\$10/lb U_3O_8	0.54				
		\$12/lb U_3O_8					0.83
		\$25/lb U_3O_8					1.77
		\$50/lb U_3O_8					3.44
b) Conversion to UF_6		\$1.35/lb U	0.07				
		\$2/kgU				0.1	
		\$2.52/kgU			0.08		
c) (a) plus (b)		\$8/lb U_3O_8 & \$2/kgU		0.42		0.5	
d) Enrichment							
	0.20%	\$26/kg SWU		0.48		0.5	
	0.20%	\$30/kg SWU					0.65
	0.275%	\$32/kg SWU			0.8		
	0.20%	\$36/kg SWU				[0.7]	0.78
	0.275%	\$36/kg SWU			[0.8]		
		\$42/kg SWU	0.76				
	0.20%	\$50/kg SWU					1.09
	0.20%	\$75/kg SWU					1.64
e) Reconversion and Fabrication		\$70/kgU	0.33		0.40	0.40	
		\$70-90/kgU		0.52			
f) Spent Fuel Shipping		\$5/kgU	0.02				
g) Reprocessing		\$35/kgU	0.14				
h) Waste Management			0.04				
i) (f) plus (g) plus (h)		\$30/kgU		0.17			
		\$40/kgU	0.20				
		\$45/kgU			0.14	0.2	
j) Plutonium Credit		\$7.50/g			(0.15)		
		\$7.70/g		(0.22)			
		\$8.00/g	(0.22)				
		\$8-10/g				(0.2)	
k) Subtotal			1.68	1.37	2.03[6]	1.6[6]	
l) Subtotal without (j)			1.90	1.59	2.18	1.8	
m) Fuel Inventory Carrying Charge or Working Capital		cost of money					
		10%				0.5	
		12%	0.82				
		Load Factor					
		0.80		0.37			
		0.70		0.42			
n) Total, excluding (j)			2.72	1.96		2.3	

Table III-1 Sources:

(1) Atomic Energy Commission, The Nuclear Industry 1973 WASH 1174-73 (1973), p. 15. This is an estimated 1981 fuel generation cost.

(2) Atomic Energy Commission, Current Status and Future Technical and Economic Potential of Light Water Reactors WASH-1082, (March 1968), p. 5-42.

(3) National Petroleum Council, "Nuclear Energy Availability" U.S. Energy Outlook, (1973), p. 14.

(4) Holdren, John P., Uranium Availability and the Breeder Decision, Environmental Quality Laboratory, January 1974, p. 13.

(5) U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and Aug 1, 1973, p. 31.

(6) Adjusted Total with enrichment costs at $36/SWU.

TABLE III-2

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant
(1980 Dollars)

Cost Component	Cost/Unit	Quantity/Yr.	Cost/Yr.	mills/kwhe
a) Mining and Milling	$20/lb U_3O_8	270,930 lbs U_3O_8	$5,418,600	.95
b) Conversion to UF_6	$5/kg U	104,192 kg U	$520,960	.09
c) Enrichment	$97/kg SWU	102,745 SWU	$9,966,265	1.75
d) Fuel Preparation and Fabrication	$112/kg U	25,622 kg U	$2,869,664	.50
e) Spent Fuel Shipping	$8/kg U	22,934 kg U	$183,472	.03
f) Reprocessing	$56/kg U	22,934 kg U	$1,284,304	.23
g) Reconversion	$2/kg U	22,705 kg U	$45,410	.01
h) Waste Management	$16/kg U	23,607 kg U	$377,712	.07
i) Shipping				
b) to c)	$.42/kg U	103,671 kg U	$43,542	
c) to d)	$.90/kg U	75,622 kg U	$23,060	
d) to d)	$.72/kg U	24,981 kg U	$17,986	
f) to g)	$1.45/kg U	22,705 kg U	$32,922	
Shipping total	-	-	$117,510	.02
Subtotal			$20,783,897	3.65
j) Fuel Inventory Carrying Charge (12 percent)			$7,497,522	1.32
k) Safeguarding			NA	-
l) Insurance			NA	-
Total (excluding k and l)			$28,281,419	4.97

Assumptions
Load factor = .65
Burnup = 30,000 MW(t)D/MTU
Efficiency = 33.5 percent
Inflation rate = 7 percent

If the SWU cost of $64.91 in 1974 was inflated annually at five percent instead of seven percent, the 1980 SWU cost would result in an annual enrichment charge of $8,938,815 or 1.57 mills/kwhe. The total cycle cost would be 4.79 mills/kwhe.

Source: Table III-3

TABLE III-3

Potential 1980 Nuclear Fuel Cycle Costs for an Average 1000 MWe Light Water Nuclear Reactor

Cost Component	Cost/Unit	Quantity/Year	Cost/Year	Mills/kwhe
a) Mining and Milling	$20/lb U_3O_8	270,930 lbs U_3O_8	$5,418,600	.95
	$8/lb U_3O_8		$2,167,440	.38
	$10/lb U_3O_8		$2,709,300	.48
	$15/lb U_3O_8		$4,063,950	.71
	$25/lb U_3O_8		$6,773,250	1.19
	$30/lb U_3O_8		$8,127,900	1.43
b) Conversion to UF_6	$3/kg U	104,192 kg U	$312,576	.06
	$2/kg U		$208,384	.04
	$4/kg U		$416,708	.07
	$5/kg U		$520.960	.09
	$6/kg U		$625,152	.11
	$7/kg U		$729,344	.13
	$8/kg U		$833,536	.15
	$9/kg U		$937,728	.16
c) Enrichment	$65/kg SWU	102,745 kg SWU	$6,678,425	1.17
	$36/kg SWU		$3,698,820	.65
	$38.50/kg SWU		$3,955,682	.69
	$42/kg SWU		$4,315,290	.76
	$50/kg SWU		$5,137,250	.90
	$60/kg SWU		$6,164,700	1.08
	$70/kg SWU		$7,192,150	1.26
	$75/kg SWU		$7,705,875	1.35
	$80/kg SWU		$8,219,600	1.44
	$90/kg SWU		$9,247,050	1.62
	$100/kg SWU		$10,274,500	1.80

TABLE III-3 Continued

Cost Component	Cost/Unit	Quantity/Year	Cost/Year	Mills/kwhe
d) Fuel Preparation and Fabrication	$70/ kg U	25,622 kg U	$1,793,540	.32
	$80/kg U		$2,049,760	.36
	$90/kg U		$2,305,980	.40
	$100/kg U		$2,562,200	.45
	$120/kg U		$3,074,640	.54
e) Spent Fuel Shipping	$5/kg U	22,934 kg U	$114,670	.02
	$10/kg U		$229,340	.04
	$15/kg U		$344,010	.06
f) Reprocessing	$35/kg U	22,934 kg U	$802,690	.14
	$40/kg U		$917,360	.16
	$45/kg U		$1,032,030	.18
	$50/kg U		$1,146,700	.20
	$60/kg U		$1,376,040	.24
	$70/kg U		$1,605,380	.28
g) Reconversion (spent fuel to UF_6)	$1/kg U	22,705 kg U	$22,705	.00
	$2/kg U		$45,410	.01
	$3/kg U		$68,115	.01
	$4/kg U		$90,820	.02
	$5/kg U		$113,525	.02

TABLE III-3 Continued

Cost Component	Cost/Unit	Quantity/Year	Cost/Year	Mills/kwhe
h) Waste Management (reactor fuel)	$10/kg U	23,607 kg U fuel	$236,070	.04
	$8/kg U		$188,856	.03
	$9/kg U		$212,463	.04
	$11/kg U		$259,677	.05
	$12/kg U		$283,284	.05
	$13/kg U		$306,981	.05
	$14/kg U		$330,498	.06
	$15/kg U		$354,105	.06
	$16/kg U		$377,712	.07
i) Shipping				
b) to c)	$.26/kg U	103,671 kg U	$26,955	
c) to d)	$.56/kg U	25,622 kg U	$14,348	
d) to d)	$.45/kg U	24,981 kg U	$11,241	
f) to g)	$.90/kg U	22,705 kg U	$20,435	
Shipping Total			$72,979	.01
i[1]) Shipping (alternative)				
b) to c)	$.42/kg U		$43,542	
c) to d)	$.90/kg U		$23,060	
d) to d)	$.72/kg U		$17,986	
f) to g)	$1.45/kg U		$32,922	
Shipping Total			$117,510	.02
Subtotal			$15,452,255	2.71
j) Fuel Inventory			$4,669,080	.82
Carrying Charge			$7,500,000	1.32
Total (initial row for each cost component)			$20,121,335	3.53
k) Safeguarding			NA	-
l) Insurance			NA	-

Nuclear Plant Assumptions
Load factor = .65
Burnup = 30,000 MW(t)D/MTU
Efficiency = 33.5 percent
Enrichment tails assay = 0.20 percent U^{235}

TABLE III-3 Sources: Cost Estimates -

a) $20/lb U_3O_8 - Commerical Sales, Rio Algom and Denison Mines, 1980 dollars.

$8/lb U_3O_8 - Atomic Energy Commission, Current Status and Future Technical and Economic Potential of Light Water Reactors (WASH-1082, March 1968), p. 5-42.

Holdren, John P., Uranium Availability and the Breeder Decision (Environmental Quality Laboratory, January 1974) p. 13.

U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and Aug. 1, 1973, p. 31.

National Petroleum Council, "Nuclear Energy Availability" U.S. Energy Outlook (1973), p. 14.

$10/lb U_3O_8 - Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73 (1973), p. 15.

$15, $25 and $30/lb U_3O_8 - Extrapolation of possible charges at $5 intervals. Some reserve estimates are made relative to $15 and $30/lb U_3O_8.

b) $3/kg U - Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73 (1973), p. 15. (1973 dollars)

$2/kg U - Holdren, John P., Uranium Availability and the Breeder Decision (Environmental Quality Laboratory, January 1974) p. 13.

$4 and $5/kg U - Extrapolations based on present costs. $3 escalated at 7% annually through 1980 yields a cost of $5.

$2 through $9/kg U - Atomic Industrial Forum, Nuclear Industry, May 1972, p. 31. The market prices of U_3O_8 and UF_6 contracted in 1972 for delivery between 1975 and 1977 show differences in cost ranging from $2.25/kg U to $9.11/kg U.

c) $65/kg SWU - U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and Aug. 1, 1973, p. 146. (1974 dollars)

$36/kg SWU - ibid., p. 31.

$38.50/kg SWU - 1974 charge

TABLE III-3 Sources Continued:

$42/kg SWU - Atomic Energy Commission, The Nuclear Industry, 1973 WASH 1174-73 (1973), p. 15.

$50 and $75/kg SWU - U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and Aug. 1, 1973, p. 31.

$60/kg SWU - Extrapolation.

$70 and $80/kg SWU - U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Part 2, Phase II, October 2, 3, and 4, 1973, pp. 102 (Hosmer) and 304 (Commonwealth Edison).

Atomic Industrial Forum, Nuclear Industry, April 1973, pp. 7-9.

The Nuclear Assurance Corporation (NAC) has calculated the component costs of a separative work unit based on AEC data. Using 1965 as a base year, three components were assessed and summed to arrive at a (ceiling) charge of $30/SWU. The components were power, labor and other costs at $15, $5, and $10, respectively. The NAC shows the power and labor costs to have escalated to $21.68 and $7.44 by 1973. The NAC assumed that all other costs including amortization, depreciation, maintenance, research and development, interest on pre-production and contingency allowances did not escalate from 1965 to 1973. By summing the three components together a (celing) charge of $39.12/SWU was found. (It should be noted that in 1973, the AEC was charging $36/SWU.) NAC projected power, labor and other costs for separative work to be $31.09, $10.80 and $10.00 respectively by 1980. This amounts to a separative work (ceiling) charge of $51.89.

A calculation of percentage increases in costs predicted by NAC reveals the following:

Time Period	Escalated Power Cost Charge $	%	%/Yr.	Escalated Labor Cost Charge $	%	%/Yr.
1/1/67 - 1/1/70	0.89	5.9	1.97	.89	16.9	5.63
1/1/70 - 1/1/73	5.67	35.4	11.80	1.29	21.0	7.00
7/1/72 - 1977	5.76	27.1	5.42	2.09	29.0	5.80
1977 - 1980	4.10	15.2	5.07	1.50	16.1	5.37
1981 - 1983	4.61	14.8	4.93	1.71	15.8	5.27

Although from 1970 to 1973 power and labor costs inflated at rates of 11.8 percent and 7.0 percent annually, NAC assumed that these costs would not continue to inflate at these rates. Rather, they forecast a decline in the rate of inflation.

TABLE III-3 Sources Continued:

Based on a 7.0 percent annual increase in costs from 1973 to 1980, the power and labor cost components in 1980 would be $34.81 and $11.95 respectively. Holding other costs constant, a (ceiling) cost of $56.76 is obtained. If power costs escalate at 11.8 percent, as they did from January 1, 1970 to January 11, 1973, a power cost of $47.33 would be encountered in 1980. This cost along with a 7 percent annual increase in labor costs, suggests a 1980 separative work unit cost of $69.28 for a government plant. These inflation rates were not assumed by the NAC. Hence they arrived at lower cost projections.

$90 and $100/kg SWU - escalations of lower costs at 7% annually through 1980.

d) $70/kg U - Atomic Energy Commission, The Nuclear Industry 1973 WASH 1174-73 (1973), P. 15. (1973 dollars)

National Petroleum Council, "Nuclear Energy Availability" U.S. Energy Outlook (1973), p. 14.

Holdren, John P., Uranium Availability and the Breeder Decision (Environmental Quality Laboratory, January 1974) p. 13.

$80 and $90/kg U - Atomic Energy Commission, Current Status and Future Technical and Economic Potential of Light Water Reactors (WASH-1082, March 1968), p. 5-42.

$100 and $120/kg U - escalation of lower costs at 7% annual through 1980.

e) $5/kg U - Atomic Energy Commission, The Nuclear Industry 1973 WASH 1174-73 (1973), p. 15. (1973 dollars)

$10 and $15/kg U - extrapolations and escalation at 7% annually National Petroleum Council, "Nuclear Energy Availability" U.S. Energy Outlook (1973), p. 14.

f) $35/kg U - Atomic Energy Commission, The Nuclear Industry 1973 WASH 1174-73 (1973), p. 15. (1973 dollars).

$40 and $45/kg U - National Petroleum Council, "Nuclear Energy Availability" U.S. Energy Outlook (1973), p. 14.

Atomic Industrial Forum, Nuclear Industry, December 1972, p. 31, $40,000/MTU (reprocessing cost).

TABLE III-3 Sources Continued:

Holdren, John P., Uranium Availability and the Breeder Decision (Environmental Quality Laboratory, January 1974) p. 13.

$50, $60 and $70/kg U - escalations of costs at 7 percent annually through 1980.

g) $1 through $5/kg U - extrapolations based on (b). (1973 dollars)

h) $10/kg fuel - Atomic Energy Commission, Nuclear Industry 1971, WASH 1174-71, p. 162. (1971 dollars)

$8 through $12/kg fuel - Idem.

$10 through $15/kg fuel - Atomic Industrial Forum, Nuclear Industry, April 1974, p. 31 (Waste Management Cost, $10,000 - $15,000/ton of processed fuel.).

$14, $15 and $16/kg fuel - escalations of costs at 7 percent annually through 1980.

i) Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH 1099, Dec. 1971, p. 94; escalated to 1973 dollars at a 7 percent annual increase from 1967 dollars.

i[1]) $117,510 - escalation of costs at 7 percent annually through 1980.

j) Atomic Energy Commission, The Nuclear Industry, 1973, WASH 1174-73 (1973), p. 15.

$7,500,000 - escalation of costs at 7 percent annually through 1980.

Quantity Estimates - Table III-3

If the cost figures used by the AEC in their fuel generation cost estimates reported in The Nuclear Industry, 1973, WASH 1174-73, are used, the fuel cycle cost is about $14,943,220 or 2.63 mills/kwhe. This cost excludes reconversion and shipping costs. It does not include a plutonium credit. Including these elements as found in Table III-2 or on page 15 (plutonium credit) of WASH 1174-73, brings the total fuel cycle cost down to 2.41 mills/kwhe. This is .09 mills/kwhe below the AEC estimate. Limiting this comparison is the fact that the average nuclear plant considered in this estimate and that implied in the AEC's estimate have different engineering and availability factors.

ponent in Table III-3. Excluding mining and milling costs, these are expressed in 1973 or 1974 dollars.[(1)] They are based on present and projected nuclear fuel cycle market indicators including current fuel contracts for delivery in the next decade, an evaluation of the enrichment industry, assuming costs are commercial and at least part of the sector is private, and recent forecasts by the AEC of future costs for each phase of the nuclear fuel cycle.

In Table III-2, an annual nuclear fuel cycle cost of $28,281,097 or 4.97 mills per kilowatt hour of electrical generation is projected for an average 1000 MWe nuclear power plant. This average plant is expected to have a 65 percent load factor, a high core burnup rate and an efficiency rating slightly above normal. The costs are reported in 1980 dollars.

Table III-3 is a composite summary of possible fuel cycle costs for the model nuclear power plant. The range of possible total nuclear fuel cycle costs from the component unit cost potentials presented in this table is from 2.41 mills to 5.70 mills per kilowatt hour of electrical generation. This is implied from annual costs ranging from $13,739,164 to $32,472,905. The lower estimate represents charges being made prior to 1974. The upper estimate represents a potential cost in 1980. The most likely component cost estimates have been summed to give a fuel cycle cost of 3.53 mills per kilowatt hour of electrical generation. This estimate is quoted mainly in 1973 dollars.[(2)]

The model plant used in this study does not possess some standard characteristics that have been assumed by the AEC in the past. In estimating fuel cycle costs, the AEC has assumed a load factor of 80 percent, a lower core burnup rate than that used by the model plant and an efficiency rating of 32.5 percent.[(3)] Table III-4 shows the fuel cycle costs, if the AEC characteristics are used. The costs are quoted in

TABLE III-4

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant Based on Historic
AEC Assumptions(1) (1980 dollars)

Cost Component	Cost/Unit	Quantity/Yr.	Cost/Yr.	mills/kwhe
a) Mining and Milling	\$20/lb U_3O_8	507 122 lbs U_3O_8	\$10,142,440	1.45
b) Conversion to UF_6	\$5/kg U	195 025 kg U	\$975,125	0.14
c) Enrichment	\$97/kg SWU	192 317 kg SWU	\$18,654,749	2.66
d) Fuel Prep and Fabrication	\$112/kg U	47 960 kg U	\$5,371,520	0.77
e) Spent Fuel Shipping	\$8/kg U	42 929 kg U	\$343,432	0.05
f) Reprocessing	\$56/kg U	42 929 kg U	\$2,404,024	0.34
g) Reconversion	\$2/kg U	42,500 kg U	\$85,000	0.01
h) Waste Management (reactor fuel)	\$16/kg U	44,189 kg U	\$707,024	0.10
i) Shipping				
b) to c)	\$.42/kg U	194,050 kg U	\$81,501	
c) to d)	\$.90/kg U	47,960 kg U	\$43,164	
d) to d)	\$.72/kg U	46,761 kg U	\$33,668	
f) to g)	\$1.45/kg U	42,500 kg U	\$61,625	
Shipping total	-	-	\$219,958	0.03
Subtotal			\$38,903,272	5.55
j) Fuel Inventory Carrying Charge (at 12%)			\$9,227,720	1.32
k) Safeguarding			NA	-
l) Insurance			NA	-
Total (excluding k and l)			\$48,130,992	6.87

Assumptions (AEC; historical)
Load factor = .80
Burnup = 20,333 MW(t)D/MTU
Efficiency = 32.5 percent
Inflation rate = 7 percent annually

Sources: Tables III-3, IIIA-1 and IIIA-4.
(1) Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Power, WASH-1099, December 1971, p. 134 and Atomic Energy Commission, The Nuclear Industry, 1973, WASH-1174-73 (1973), p. 15.

1980 dollars and show a total fuel cycle cost of 6.87 mills per kilowatt hour of electrical generation. This is implied from an annual cost of $48,130,992. The cost is 1.9 mills greater than that found for the model plant.

The assumptions concerning the technical and operational levels and requirements of the model 1000 MWe light water nuclear power plant determine the quantity flow of uranium, from which the costs are estimated. The percentage distribution of the isotope U^{235} in the enriched uranium and the uranium waste or tails separated in the enrichment process affect the amount of uranium moving through the first three stages of the fuel cycle but not the cost.

The cost of enrichment is measured by the amount of work required to separate uranium into an enriched product with a higher concentration of U^{235} and a low-level waste. Small changes in the degree of enrichment alters costs only slightly. An increase in the percentage of U^{235} allowed in the waste increases the amount of feed needed to produce a kilogram of enriched uranium, but the amount of separative work is decreased.(4) As shown in Table III-5, the net cost effect is minimal.

The enriched uranium requirements for initial and subsequent core loadings for a nuclear power plant are dependent on three factors. First, the plant's irradiation or core burnup rate. This is the rate of production of thermal power per unit of enriched uranium stated in megawatt days (thermal) per metric ton of uranium. This varies under certain conditions: (1) the initial core irradiation level is lower than the steady state (subsequent) levels. For purposes of calculation, it should be noted that over the plant's life (30 years) the average irradiation level approaches the steady state level, while over a ten year span the levelized rate averages slightly less than the steady state level. (2) these levels are lower

TABLE III-5

A Comparison of Fuel Cycle Component Costs for
an Average 1000 MWe Nuclear Power Plant
Using Different Enrichment Tails Assays

Cost Component	Cost/Unit	0.20 Percent Tails Assay Quantity/Yr	0.20 Percent Tails Assay Cost/Yr	0.20 Percent Tails Assay Mills/kwhe	0.30 Percent Tails Assay Quantity/yr	0.30 Percent Tails Assay Cost/Yr	0.30 Percent Tails Assay Mills/kwhe
Mining and Milling	a) $20/lb U_3O_8	270,930 lbs U_3O_8	$5,418,600	.95	338,910 lbs U_3O_8	$6,778,200	1.19
	b) $8/lb U_3O_8		$2,167,440	.38		$2,711,280	.48
	c) $10/lb U_3O_8		$2,709,300	.48		$3,389,100	.60
	d) $15/lb U_3O_8		$4,063,950	.71		$5,083,650	.89
	e) $25/lb U_3O_8		$6,773,250	1.19		$8,472,750	1.49
	f) $30/lb U_3O_8		$8,127,900	1.43		$10,167,300	1.79
Conversion to UF_6	g) $3/kg U	104,192 kgs U	$312,576	.06	130,335 kgs U	$391,005	.07
Enrichment	h) $65/kg SWU	102,745 kg SWU	$6,678,425	1.17	87,724 kg SWU	$5,702,060	1.00
	i) $36/kg SWU		$3,698,820	.65		$3,158,064	.55
	j) $38.50/kg SWU		$3,955,682	.69		$3,377,374	.59
	k) $42/kg SWU		$4,315,290	.76		$3,684,408	.65
	l) $50/kg SWU		$5,137,250	.90		$4,386,200	.77
	m) $60/kg SWU		$6,164,700	1.08		$5,263,440	.92
	n) $70/kg SWU		$7,192,150	1.26		$6,140,680	1.07
	o) $80/kg SWU		$8,219,600	1.44		$7,017,920	1.23
	p) $90/kg SWU		$9,247,050	1.62		$7,895,160	1.39
	q) $100/kg SWU		$10,274,500	1.80		$8,772,400	1.54
Total (rows a, g and h)			$12,409,601	2.18		$12,871,265	2.26
(rows c, g and k)			$7,337,166	1.29		$7,464,513	1.31

Nuclear Plant Assumptions:

Load factor = .65
Burnup = 30,000 MW(t)D/MTU
Efficiency = 33.5 percent

Source: Tables III-3 and III-7.

Note: Totals are rounded.

for boiling water reactors (BWR) than they are for pressurized water reactors (PWR).[5] Second, with respect to the thermal to electrical conversion efficiency, the higher the efficiency the lower the uranium requirement. The efficiency tends to be higher for BWR's than PWR's. Third, the nuclear plant's load factor (percent time the nuclear plant produces electricity): the higher the load factor, the greater the quantity of uranium needed. Together, these three factors determine the annual uranium loading requirements for a nuclear reactor. The following equation expresses this relationship.

$$R = \frac{e \times k \times 8760 \text{ hours}}{b \times eff \times 24 \text{ hours/day}}$$

R = the annual enriched uranium requirement for the nuclear reactor (kilograms of enriched uranium)

b = the core burnup rate (MW(t)days/metric tons U)

eff = the reactor's thermal to electrical conversion efficiency

k = the nuclear plant's load factor

e = plant size |KW(e)|

For consistency, in this paper the nuclear plant size has been fixed at 1000 MWe, with an availability factor of 0.65. The 0.65 availability factor requires less uranium in each step of the cycle than if the usual AEC load factor of 0.80 had been used. This means that both the component and total annual fuel cycle costs are lower for a plant generating electricity 65 percent of the time than for a plant generating electricity 80 percent of the time. In terms of mills per kilowatt hour of electrical generation,[6] the different availability factors have very little affect on cost.[7]

The major factor affecting the quantity of uranium cycled and the cost of acquiring and recycling uranium is the

engineering capability of the plant. Here, the principal components are: the irradiation or core burnup rate of the plant, the efficiency with which thermal generation is converted to electrical generation, the level of uranium enrichment required for loading the reactor, and the level of uranium enrichment remaining in the reactor's discharge.

In Tables III-2 and III-3, the nuclear plant is assumed to be a light water reactor with an average core burnup rate of 30,000 megawatt days (thermal) per metric ton of uranium[8] and a thermal plant capacity of 2985 megawatts. The thermal plant capacity is based on an efficiency rating of 33.5 percent. This is slightly above the historic average shown in Table III-6. There it is shown that efficiency ratings have varied by plant from 19.8 to 35.9 percent. Nuclear plants with installed electrical capacity levels above 1000 MWe have experienced efficiency ratings of 33.3 and 33.4 percent. Furthermore, it is expected that the reactor will operate with 3.0 percent enriched uranium and will discharge a 0.85 percent enriched uranium.[9] Changing the core burnup rate significantly affects both the quantity of uranium passing through the fuel cycle and the cost of the cycle.[10] In general, the higher the burnup rate the lower the demand for uranium feed. Therefore, when a high burnup rate is used, the result is lower fuel cycle costs, both total cost and in terms of mills per kilowatt hour. In order to introduce a bias towards low costs, the model nuclear plant analyzed in this study is assumed to have a high ten year levelized burnup.[11]

As an example of how these conditions factor into the annual uranium requirement for the model nuclear plant, the following is representative:

TABLE III-6

Thermal to Electrical Conversion

Efficiencies of Nuclear Power Reactors

Nuclear Plant	Installed Capacity Thermal MW	Electrical MW(gross)	Efficiency
Shippingport	505	100	.198
Dresden 1	700	210	.300
Yankee	600	185	.308
Indian Point 1	615	285	.463
Big Rock Point	240	75	.312
Humbolt Bay	240	75	.312
Peach Bottom 1	115	42	.365
N/WPPSS	4000	860	.215
Oyster Creek	1930	670	.347
Genoa	165	55	.333
Nine Mile Point	1850	640	.346
Ginna 1	1455	490	.337
Robinson 2	2200	739	.336
Millstone 1	2011	682.3	.339
Point Beach 1	1518	524	.345
Dresden 2	2527	850	.336
Dresden 3	2527	850	.336
Monticello	1670	568.7	.340
Palisades	2212	722	.326
Quad Cities 1	2511	850	.338
Vermont Yankee	1593	537.3	.337
Quad Cities 2	2511	850	.339
Point Beach 2	1518	524	.345
Pilgrim 1	1998	687	.344
Surry 1	2441	824	.338
Turkey Point 3	2200	728	.331
Maine Yankee	2440	827	.339
Surry 2	2441	824	.338
Oconee 1	2568	922.5	.359
Indian Point 2	2758	906	.328
Turkey Point 4	2200	728	.330
Zion 1	3250	1086	.334
Fort Calhoun 1	1420	481.5	.339
Browns Ferry 1	3293	1098.4	.333
Oconee 2	2568	922.5	.359
Zion 2	3250	1086	.334
TOTAL	68,040	22,505.2	.331

Source: Atomic Energy Commission, Operating History of U.S. Nuclear Power Reactors, WASH - 1203-73, 1973.

Annual uranium input = 23,607 KgU =

$$\frac{1{,}000{,}000\,\text{KW(e)} \times 0.65 \times 8760\ \text{hours}}{30{,}000\ \frac{\text{KW(t) days}}{\text{KgU}} \times 0.335\ \frac{\text{KW(e)}}{\text{KW(t)}} \times 24\ \frac{\text{hrs}}{\text{day}}}$$

Where: burnup = $30{,}000\ \frac{\text{KW(t) D}}{\text{KgU}}$

efficiency = $0.335\ \frac{\text{KW(e)}}{\text{KW(t)}}$

load factor = 0.65

plant size = 1000 MWe

The amount of uranium that will flow through each step in the fuel cycle can be determined once the nuclear reactor load requirements are calculated. What needs to be known is how much uranium is lost and recycled at each step and some assumptions concerning enrichment. As an example, Table III-7 shows that 23,607 kilograms of 3.0 percent enriched uranium enters the model reactor yearly. This uranium comes from a fuel fabrication plant where it is assumed that 0.5 percent is lost during fabrication.[12] Five percent of the uranium going through this process is recycled. To determine the number of kilograms of uranium (F) that must enter the fabrication plant, it is necessary to solve the following equation:

$$F = 23{,}607\ \text{kg U} / (1-0.055).$$

The UO_2 in the fabrication plant was converted from UF_6 which had previously been enriched to 3.0 percent U^{235}. In this process it is assumed that there is a 0.5 percent loss of uranium and a 2.0 percent recycling of material not properly prepared. The amount of uranium (P) that enters into this step fits the equation:

$$P = F / (1-0.025).$$

TABLE III-7

Uranium Flow for a Typical
1000 MWe Light Water Reactor

		Uranium Kg/Year	Percentage Weight of U^{235}	SWU/Year
Conversion (0.5% loss)	(in)	104 192	.711	
	(out)	103 671	.711	
Enrichment	(regular in)	103 671	.711	
	(regular out)	18 922	3.0	81 478
	(recycled in)	22 636	.85	
	(recycled out)	4 939	3.0	21 267
	(out)	23 861	3.0	102 745
Recycled U		1 761	3.0	
Fuel Preparation	(in)	25 622	3.0	
(2% recycled)	(recycled)	512	3.0	
(0.5% loss)	(out)	24 981	3.0	
Fabrication	(in)	24 981	3.0	
(5% recycled)	(recycled)	1 249	3.0	
(0.5% loss)	(out)	23 607	3.0	
Reactor	(in)	23 607	3.0	
	(out)	22 934	.85	
Reprocessing	(in)	22 934	.85	
(1% loss)	(out)	22 705	.85	
Conversion	(in)	22 705	.85	
(0.3% loss)	(out)	22 636	.85	
Enrichment	(in)	22 636	.85	
	(tails)	17 697	.20	
	(out)	4 939	3.0	21 267

Assumptions:

Load Factor = .65
Burnup = 30,000 MW(t)D/MTU
Efficiency = 33.5 percent
104,192 KgU = 122,871 KgU_3O_8 = 270,930 lbs U_3O_8
Enrichment tails assay = 0.20 percent U^{235}

Source: Table III-9

Subtracting from this figure (P), the amount of uranium recycled in the two processes, indicates the amount of uranium in the form of UF_6 that must be produced by the gaseous diffusion enrichment process. In Table III-7 this is shown to be 23,861 kg U. Some of this enriched product will be the result of reconditioning converted spent fuel from the nuclear reactor but most will be converted natural uranium from the mill.

The amount of uranium lost during the enrichment process is dependent on the percentage weight of the U^{235} isotope in the uranium going into the gaseous diffusion plants (spent fuel typically has a higher assay than the .711 percent of natural uranium), the percentage weight to which the uranium is to be enriched, and the tails assay. A relatively high tails assay (a high percentage weight of U^{235} in the waste) implies that a relatively high feed component is needed per kilogram of enriched uranium produced.(13) This means that the higher the tails assay (all other factors remaining constant) the higher will be the waste or material lost in the enrichment process. Additionally, the desired level to which the uranium is to be enriched directly affects the feed and waste components,(14) while the amount of U^{235} in the fuel inversely affects these components.

The number of separative work units(15) must be changed with changes in each of the factors noted above. This affects the enrichment cost but not the amount of uranium feed. The fact that changing all or some of these factors changes the cost at this point of the fuel cycle does not mean that the total fuel cycle costs are changed significantly.(16) This is due to an offsetting effect that occurs at the mill. In general, the more feed used to produce equivalent units of enriched uranium, the less the number of separative work units necessary. This assumes the tails compensation noted above.

A comparison between Tables III-7 and III-7A shows the relationship between conversion and enrichment and the tails

TABLE III-7A

Enrichment and Conversion of Uranium
for a 1000 MWe Light Water Reactor
(0.3 Percent Tails Assay After Enrichment)

		Uranium Kg/Year	Percentage weight of U^{235}	SWU/Year
Conversion (0.5% loss)	(in)	130 335	.711	
	(out)	129 683	.711	
Enrichment	(regular in)	129 683	.711	
	(regular out)	19 742	3.0	67 616
	(recycled in)	22 636	.85	
	(recycled out)	4 119	3.0	14 108
	(out)	23 861	3.0	87 724

Assumptions: Load factor = .65

Burn up = 30,000 MW(t)D/MTU

Efficiency = 33.5 percent

130,335 KgU = 153,700 KgU_3O_8

= 338,910 lbs U_3O_8

Enrichment tails assay = 0.30 percent U^{235}

Source: Tables III-8 and III-9

assay. At the higher 0.3 percent tails assay (Table III-7A) with recycling, to obtain 23,861 kilograms of uranium per year from the enrichment process requires a greater amount of feed and fewer separative work units than that shown in Table III-7. In the present case, 130,335 kilograms of uranium are converted yearly using 87,724 separative work units. This may be compared to Table III-7, where the figures are 104,192 KgU and 102,745 SWU, respectively. Table III-5 corresponds directly with the quantities developed above. It shows that at the anticipated costs per unit, the total cost difference due to alternate tails assays is less than 0.1 mills per kilowatt hour of electricity.

In Table III-7, the uranium is enriched to 3.0 percent U^{235}; in the enrichment process the .711 percent U^{235} uranium feed is separated into a 0.2 percent waste component and a 3.0 percent enriched product. The ratio of natural uranium feed to product and the amount of SWU's needed was derived from Table III-8.

In Table III-8, the uranium feed is natural uranium converted to the form UF_6. However, not all the uranium that enters the government gaseous diffusion plants is natural uranium. Some of it has a higher percent of U^{235}. This uranium is in the form of spent fuel discharged from the nuclear reactor. Since this feed is richer in U^{235} than the feed considered in this table, it is logical to assume that it will take less feed to produce a unit of enriched product.

In the example under consideration, it is known that 23,607 KgU of 3.0 percent enriched uranium will be used annually in the reactor and that 23,861 KgU of 3.0 percent enriched uranium will come from the gaseous diffusion plants annually. This product comes from servicing both spent fuel and natural feed. How much of each can be calculated by examining the recycling process.

TABLE III-8

Feed and Separative Work to Produce 1 kg U of 3 Percent Enriched Uranium

Tails assay (Percent weight U^{235})	Feed component (KgU feed per KgU product)	Separative work component (SWU per KgU product)	Tails assay (Percent weight U^{235})	Feed component (KgU feed per KgU product)	Separate work component (SWU per KgU product)
0.10	4.746	5.981	0.28	6.311	3.569
0.14	5.009	5.114	0.30	6.569	3.425
0.18	5.311	4.518	0.32	6.854	3.291
0.20	5.479	4.306	0.36	7.521	3.054
0.22	5.662	4.092	0.40	8.360	2.847
0.24	5.860	3.900	0.45	9.770	2.623
0.26	6.075	3.727	0.50	11.848	2.429

Source: Reprint: U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and August 1, 1973, p. 39.

In Table III-7, it is assumed that 97 percent of the uranium entering the reactor is discharged as spent uranium fuel with an assay of 0.85 percent. The rest is discharged in the form of plutonium, fissile products and other materials which must be stored or deposited. This means, that if 23,607 KgU of 3.0 percent enriched uranium goes into the reactor, 22,934 KgU of spent uranium fuel with an assay of 0.85 percent comes out.(17) This can be sent to the enrichment plant for recycling. Assuming a 1.0 percent loss of material during reprocessing and a 0.3 percent loss of material during conversion,(18) 22,636 kilograms of 0.85 percent enriched uranium reaches the gaseous diffusion plants yearly. The method of deriving this is as follows:

If: R = kilograms of uranium entering the reactor annually

D = kilograms of uranium leaving the reactor (to be reprocessed) annually

C = kilograms of uranium entering the conversion process annually

E = kilograms of uranium entering the enrichment plants annually,

then:

$$D = (.97)R$$

$$C = D - (0.01)D$$

$$E = C - (0.003)C = (.997)(.99)(.97)R = (.957)R$$

The spent fuel feed reaching the diffusion plants is 0.85 percent enriched. Table III-8 shows that 5.479 kilograms of natural uranium is needed to produce one kilogram of 3.0 percent enriched uranium when a 0.2 percent tails assay is used. But, 0.8365 kilograms of 0.85 percent enriched uranium contains the same weight of U^{235} as one kilogram of natural uranium (.711 percent). By fixing the separative work component at 4.306 SWU, proportionally it would take 4.583 kilograms

of 0.85 percent enriched uranium to produce one kilogram of 3.0 percent enriched uranium.[19] This is a rough estimate. It is possible that the SWU requirements change with differing feeds. However, it is assumed that this type of change is very small and is disregarded. From the above, the amount of 3.0 percent enriched recycled uranium produced in an enrichment plant annually from feed supplied by the model 1000 MWe nuclear plant, is about 4000 KgU. This is estimated as follows:

If: E = kilograms of 0.85 percent spent uranium entering the enrichment process annually

S = kilograms of 3.0 percent enriched uranium produced from spent fuel annually,

then: $S = E / 4.583$

The rest of the enriched uranium must come from converted natural uranium. Since 4939 kilograms of the 23,961 kilograms of enriched uranium that leaves the enrichment plants has been accounted for, only 22,636 KgU must be traced to the source. Referring to Table III-7, the amount of feed necessary to produce this much enriched uranium is 103,671 KgU. This is calculated as follows:

If: P = kilograms of enriched uranium entering the feed preparation plant annually

r = kilograms of uranium recycled in the fuel preparation and fabrication process annually

Enr = kilograms of enriched uranium produced in the gaseous diffusion plant annually

S = kilograms of enriched uranium produced from the spent fuel annually

B = kilograms of enriched uranium produced from converted natural feed annually

N = kilograms of converted natural (.711 percent U^{235}) uranium fed to the enrichment process annually,

then:

$$Enr = P - r$$
$$B = Enr - S$$
$$N = B \times 5.479$$

In the conversion of natural uranium to UF_6, the enrichment feed, the loss of uranium is assumed to be 0.5 percent.[20] Therefore, if 103,671 kilograms of uranium is needed by the gaseous diffusion plants, 104,192 KgU is needed by the conversion plants. This is the amount of uranium that must be purchased from the uranium mills annually, and can be derived in this way:

If: N = kilograms of converted natural uranium feed entering the enrichment plants annually

U = kilograms of natural uranium converted to UF_6 annually,

then: $U = N / (1-0.005)$

For the cost analysis of the fuel cycle two further calculations are required. Because milled uranium is sold by the pound and the enrichment charge is based on SWU's and because all other processing activity is costed relative to the number of kilograms of uranium affected, it is necessary to convert the kilogram figures to pounds. There are 104,192 kilograms of uranium in 122,871 kilograms of U_3O_8 (or 270,930 pounds of U_3O_8).[21] The separative work units are derived from Table III-8, i.e., (23,861 KgU) x (4.306 SWU's) = 102,745 KgSWU's.

Table III-9 is a summary of the equations used to justify the quantity estimates.

The method involved in calculating the amount of uranium entering each stage of the cycle is based on the method

TABLE III-9

Equations for Deriving the
Annual Uranium Flow for a Typical
1000 MWe Light Water Reactor

		Equations for Deriving Kilograms U/yr.	U^{235} Percent Weight	Formulas for Deriving SWU's/yr.
Conversion (0.5% loss)	(in)	U = N/.995	.711	
	(out)	N	.711	
Enrichment	(regular in)	N = (5.479)B	.711	
	(regular out)	B = Enr -S	3.0	B(4.306)
	(recycled in)	E	.85	
	(recycled out)	S	3.0	S(4.306)
	(out)	Enr=P-r	3.0	Enr(4.306)
Recycled U		r = (0.02P)+(0.05F)	3.0	
Fuel Preparation	(in)	P = F/.975	3.0	
(2% recycled)	(recycled)	(0.02)P	3.0	
(0.5% loss)	(out)	F	3.0	
Fabrication	(in)	F = R/.945	3.0	
(5% recycled)	(recycled)	(0.05)F	3.0	
(0.5% loss)	(out)	R	3.0	
Reactor	(in)	$R=\frac{(e)(k)(8760\text{hrs})}{(b)(eff)(24\text{hrs/day})}$	3.0	
	(out)	D=(0.97)R	.85	
Reprocessing	(in)	D	.85	
(1% loss)	(out)	C=(0.99)D	.85	
Conversion (0.3% loss)	(in)	C	.85	
	(out)	E=(0.997)C	.85	
Enrichment	(in)	E	.85	
	(tails)	E-S	.2	
	(out)	S=E/4.583	3.0	

Sources: Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH-1099, Dec. 1971, p. 134.

Atomic Energy Commission, Forecast of Growth of Nuclear Power, WASH-1139, January 1971, p. 18.

U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase 1, July 31 and August 1, 1973, p. 3[illegible].

TABLE III-9 Continued

Notation

U = kilograms of natural uranium entering conversion (leaving the mill)

N = kilograms of natural uranium entering enrichment (leaving conversion)

B = kilograms of enriched uranium leaving regular enrichment

E = kilograms of spent uranium entering (re) enrichment (leaving (re)conversion)

S = kilograms of enriched uranium leaving (re) enrichment

Enr = kilograms of enriched uranium leaving total enrichment

r = kilograms of recycled uranium from fuel preparation and fabrication

P = kilograms of enriched uranium entering fuel preparation

F = kilograms of enriched uranium entering fabrication (leaving fuel preparation)

R = kilograms of enriched uranium entering the reactor (leaving fabrication)

D = kilograms of spent uranium entering reprocessing (leaving the reactor)

C = kilograms of spent uranium entering (re) conversion (leaving reprocessing)

e = nuclear plant size (megawatts of electricity)

k = nuclear plant availability factor

b = levelized nuclear core burnup rate (MW(t)days/MTU)

eff = the nuclear reactor's thermal to electrical conversion efficiency [MW(e) / MW(t)]

for deriving the fuel requirements for the nuclear reactor alone. All calculations in the fuel cycle ultimately come back to this factor. In Table III-9, the method is presented. Basically, it involves dividing the nuclear plants electrical generating capacity by the nuclear core's fuel burnup rate and the plant's thermal to electrical conversion efficiency. In order to determine the margin of error in this method of calculations, it was used on specific AEC data in order to compare the results with those reported by the AEC. Referring to Table III-10, the AEC estimates an annual nuclear plant loading requirement of 46,782 kilograms of uranium. If the plant assumptions listed at the end of the table are fitted into the equation for deriving fuel loading levels, an error of 0.36 percent is determined. That is,

$$R = \frac{\left|1{,}000{,}000\ \mathrm{Kw(e)}\right|\ (.85)(8760\ \mathrm{hrs})}{(20{,}333\ \mathrm{Kw(t)\ days/KgU})\ \left|\frac{100\ \mathrm{Kw(e)}}{3077\ \mathrm{Kw(t)}}\right|\ (24\ \mathrm{hrs/day})}$$

$$R = 46{,}950$$

The difference between the AEC calculation of R and the one based on the methodology presented in this paper is 168 kilograms or 0.36 percent.

TABLE III-10

Uranium Flow for a Typical
1000 MWe Light Water Reactor

		Uranium Kg/Year	Percentage Weight of U^{235}	SWU/Year
Conversion (0.5% loss)	(in)	146 391	.711	
	(out)	145 659	.711	
Enrichment	(regular in)	145 659	.711	
	(recycled in)	44 859	1.016	
	(out)	47 284	2.548	139 380
Recycled U		3 490	2.548	
Fuel Preparation (2% recycled) (0.5% loss)	(in)	50 774	2.548	
	(recycled)	1 015	2.548	
	(out)	49 505	2.548	
Fabrication (5% recycled) (0.5% loss)	(in)	49 505	2.548	
	(recycled)	2 475	2.548	
	(out)	46 782	2.548	
Reactor	(in)	46 782	2.548	
	(out)	45 448	1.016	
Reprocessing (1% loss)	(in)	45 448	1.016	
	(out)	44 994	1.016	
Conversion (0.3% loss)	(in)	44 994	1.016	
	(out)	44 859	1.016	
Enrichment	(in)	44 859	1.016	

Assumptions:
Load factor = .85
Burnup = 20,333 MW(t)D/MTU
Efficiency = 32.5 percent
146,391 KgU = 172,635 KgU_3O_8 = 380,660 lbs U_3O_8

Enrichment tails assay = 0.20 percent U^{235}

Source: Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH-1099, December 1971, p. 134.

TABLE IIIA-1

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant

Cost Component	Cost/Unit	Quantity/Yr.	Cost/Yr.	mills/kwhe
a) Mining and Milling	\$20/lb U_3O_8	507 122 lbs U_3O_8	\$10,142,440	1.45
b) Conversion to UF_6	\$3/kg U	195 025 kg U	\$585,075	.08
c) Enrichment	\$65/kg SWU	192 317 kg SWU	\$12,500,605	1.78
d) Fuel Prep and Fabrication	\$70/kg U	47 960 kg U	\$3,357,200	.48
e) Spent Fuel Shipping	\$5/kg U	42 929 kg U	\$214,645	.03
f) Reprocessing	\$35/kg U	42 929 kg U	\$1,502,515	.22
g) Reconversion	\$1/kg U	42 500 kg U	\$42,500	.01
h) Waste Management	\$10/kg U (reactor fuel)	44 189 kg U (reactor fuel)	\$441,890	.08
i) Shipping				
b) to c)	\$.26/kg U	194,050 kg U	\$50,453	
c) to d)	\$.56/kg U	47,960 kg U	\$26,858	
d) to d)	\$.45/kg U	46,761 kg U	\$21,042	
f) to g)	\$.90/kg U	42,500 kg U	\$38,250	
Shipping Total			\$136,603	.02
Subtotal			\$28,923,473	4.13
j) Fuel Inventory Carrying Charge (at 12%)			\$5,746,560	.82
k) Safeguarding				
l) Insurance			---	
Total (without k and l)			\$34,670,033	4.95

Assumptions:
Load factor = .80
Burnup = 20,333 MW(t)D/MTU
Efficiency = 32.5 percent

Mining and milling costs are quoted in 1980 dollars.
Enrichment costs are quoted in 1974 dollars.
All other unit costs are quoted in 1973 dollars.

Sources: Tables III-3, III-9, and IIIA-4.

SECTION III APPENDIX A: EFFECT OF PARAMETERS ON FUEL CYCLE COSTS

Assumptions concerning the operational and technical parameters of a nuclear power plant play a major role in determing the fuel cycle costs. The effect of changed assumptions are shown in the fuel cycle costs presented in Tables IIIA-1 through IIIA-3 (and Tables III-2 and III-4). In Table IIIA-1 a load factor of 80 percent, a burnup rate of 20,333 MWD(t)/MTU, and an efficiency level of 32.5 percent are assumed. Table IIIA-2 differs from Table IIIA-1 in that a burnup rate of 30,000 MWD(t)/MTU is used. Table IIIA-3 differs from IIIA-2 because a load factor of 65 percent and an efficiency rating of 33.5 percent is used.

The increase in the burnup rate by 10,000 MWD(t)/MTU results in a fuel cycle cost decrease of 1.4 mills per kilowatt hour. The changes in the load factor and efficiency ratings result in a fuel cycle cost change of less than 0.05 mills per kilowatt hour. In order to introduce downward cost bias, the assumptions in Table IIIA-3 were adopted for the model plant analyzed in this study.

Tables IIIA-4 and IIIA-5 are source tables for tables IIIA-1 and IIIA-2. They show the quantity or uranium that must be processed in the fuel cycle given the assumptions listed. The source table for Table IIIA-3 is Table III-7.

TABLE IIIA-2

1980 Fuel Cycle Costs for an
Average 1000 MWe
Nuclear Power Plant

Cost Component	Cost/Unit	Quantity/Yr	Cost/Yr	Mills/kwhe
a) Mining and Milling	\$20/lb U_3O_8	326 178 lbs U_3O_8	\$6,523,560	0.93
b) Conversion to UF_6	\$3/kg U	125 439 kg U	\$376,317	0.05
c) Enrichment	\$65/kg SWU	130 343 Kg SWU	\$8,472,295	1.21
d) Fuel Prep and Fabrication	\$70/kg U	32 505 kg U	\$2,275,350	0.33
e) Spent Fuel Shipping	\$5/kg U	29 095 kg U	\$145,475	0.02
f) Reprocessing	\$35/kg U	29 095 kg U	\$1,018,325	0.15
g) Reconversion	\$1/kg U	28 804 kg U	\$28,804	0.00
h) Waste Management	\$10/kg U (reactor fuel)	29 949 kg U (reactor fuel)	\$299,490	0.04
i) Shipping				
b) to c)	\$.26/kg U	124 812 kg U	\$32,451	
c) to d)	\$.56/kg U	32,505 kg U	\$18,203	
d) to d)	\$.45/kg U	31,692 kg U	\$14,261	
f) to g)	\$.90/kg U	28,804 kg U	\$25,924	
Shipping Total			\$90,839	0.01
Subtotal			\$19,230,455	2.74
j) Fuel Inventory Carrying Charge (at 12%)			\$5,746,560	0.82
k) Safeguarding			NA	-
l) Insurance			NA	-
Total (without k and l)			\$24,977,015	3.56

Assumptions:
Load factor = .80
Burnup = 30,000 MW(t)D/MTU
Efficiency = 32.5 percent

*Mining and milling costs are quoted in 1980 dollars.
Enrichment costs are quoted in 1974 dollars.
All other unit costs are quoted in 1973 dollars.

Sources: Tables III-3, III-9 and IIIA-5.

TABLE IIIA-3

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant

Cost Component	Cost/Unit	Quantity/Yr.	Cost/Yr.	mills/kwhe
a) Mining and Milling	$20/lb U_3O_8	270,930 lbs U_3O_8	$5,418,600	.95
b) Conversion to UF_6	$3/kg U	104,192 kg U	$312,576	.06
c) Enrichment	$65/kg SWU	102,745 SWU	$6,678,425	1.17
d) Fuel Prep and Fabrication	$70/kg U	25,622 kg U	$1,793,540	.32
e) Spent Fuel Shipping	$5/kg U	22,934 kg U	$114,670	.02
f) Reprocessing	$35/kg U	22,934 kg U	$802,690	.14
g) Reconversion	$1/kg U	22,705 kg U	$22,705	.00
h) Waste Management	$10/kg U (reactor fuel)	23,607 kg U (reactor fuel)	$236,070	.04
i) Shipping				
b) to c)	$.26/kg U	103,671	$26,955	
c) to d)	$.56/kg U	25,622	$14,348	
d) to d)	$.45/kg U	24,981	$11,241	
f) to g)	$.90/kg U	22,705	$20,435	
			$72,979	.01
Subtotal			$15,452,255	2.71
j) Fuel inventory carrying charge (at 12%)			$4,669,080	.82
k) Safeguarding			NA	-
l) Insurance			NA	-
Total (without k and l)			$20,121,335	3.53

Assumptions:
Load factor = .65
Burnup = 30,000 MW(t)D/MTU
Efficiency = 33.5 percent

Mining and milling costs are quoted in 1980 dollars.
Enrichment costs are quoted in 1974 dollars.
All other unit costs are quoted in 1973 dollars.

Sources: Tables III-3, III-7 and III-9.

TABLE IIIA-4

Uranium Flow for A Typical
1000 MWe Light Water Reactor

		Uranium Kg/Year	Percentage Weight of U^{235}	SWU/Year
Conversion	(in)	195 025	.711	
(0.5% loss)	(out)	194 050	.711	
Enrichment	(regular in)	194 050	.711	
	(regular out)	35 417	3.0	152 506
	(recycled in)	42 372	.85	
	(recycled out)	9 246	3.0	39 811
	(out)	44 663	3.0	192 317
Recycled U		3 297	3.0	
Fuel Preparation	(in)	47 960	3.0	
(2% recycled)	(recycled)	959	3.0	
(0.5% loss)	(out)	46 761	3.0	
Fabrication	(in)	46 761	3.0	
(5% recycled)	(recycled)	2 338	3.0	
(0.5% loss)	(out)	44 189	3.0	
Reactor	(in)	44 189	3.0	
	(out)	42 929	.85	
Reprocessing	(in)	42 929	.85	
(1% loss)	(out)	42 500	.85	
Reconversion	(in)	42 500	.85	
(0.3% loss)	(out)	42 372	.85	
Enrichment	(in)	42 372	.85	
	(tails)	33 126	.20	39 811
	(out)	9 246	3.0	

Assumptions:
Load factor = .80
Burnup = 20,333 MW(t)D/MTU
Efficiency = 32.5 percent
195,025 KgU = 229,987 KgU_3O_8 = 507,122 lbs U_3O_8
Enrichment tails assay = 0.20 percent U^{235}

Source: Table III-9.

TABLE IIIA-5

Uranium Flow for a Typical

1000 MWe Light Water Reactor

		Uranium Kg/Year	Percentage Weight of U^{235}	SWU/Year
Conversion	(in)	125,439	.711	
(0.5% loss)	(out)	124,812	.711	
Enrichment	(regular in)	124,812	.711	
	(regular out)	22,780	3.0	98,091
	(recycled in)	28,718	1.016	
	(recycled out)	7,490	3.0	32,252
	(out)	30,270	3.0	130,343
Recycled U		2,235	3.0	
Fuel Preparation	(in)	32,505	3.0	
(2% recycled)	(recycled)	650	3.0	
(0.5% loss)	(out)	31,692	3.0	
Fabrication	(in)	31,692	3.0	
(5% recycled)	(recycled)	1,585	3.0	
(0.5% loss)	(out)	29,949	3.0	
Reactor	(in)	29,949	3.0	
	(out)	29,095	1.016	
Reprocessing	(in)	29,095	1.016	
(1% loss)	(out)	28,804	1.016	
Reconversion	(in)	28,804	1.016	
(0.3% loss)	(out)	28,718	1.016	
Enrichment	(in)	28,718	1.016	
	(tails)	21,228	.20	
	(out)	7,490	3.0	32,252

Assumptions:
- Load factor = .80
- Burnup = 30,000 MW(t)D/MTU
- Efficiency = 32.5 percent
- 125,439 KgU = 147,926 KgU_3O_8 = 326,178 lbs U_3O_8
- Enrichment tails assay = 0.20 percent U^{235}

Sources: Table III-9 and III-10.

SECTION III APPENDIX B: FUEL CYCLE COSTS - AEC BASIS

Information supplied by C. E. Larson, Commissioner, Atomic Energy Commission, provided some precise nuclear plant assumptions.[22] These yielded fuel cycle costs approximately equal to those found for the model plant considered in this study. Furthermore, the calculated average burnup rates and efficiency levels serve to justify those assumed for the model plant. The load factor was higher than that found historically but, as shown in Appendix IIIA, Tables IIIA-2 and IIIA-3, this has very little effect on total fuel cycle costs.

Tables IIIB-1 and IIIB-2 present nuclear fuel cycle costs based on the assumptions listed at the end of each table. Over a 30 year period, such a plant would experience a fuel cycle cost of 4.96 mills per kilowatt hour of electrical generation (mills/kwhe). This cost, in terms of 1980 dollars, should be compared with the cost of 4.97 mills/kwhe for the model plant in Table III-2. If the fuel cycle costs for the nuclear plant using Commissioner Larson's assumptions were assessed after ten years of operation, the fuel cycle cost would be 5.22 mills/kwhe.

Table IIIB-3 and IIIB-4 present the computed annual uranium flow through the fuel cycle and serve as back-up tables to Tables IIIB-1 and IIIB-2. The methodology for computing the amount of uranium passing through each process was slightly different than that used previously in this study. Instead of calculating the amount of natural uranium that must enter the enrichment process and the separative work needed from Table III-8, the amounts were determined from Tables IIIB-5 and IIIB-6. Both of these tables account for recycled uranium. The remainder of the calculations were made exactly as stated before. Tables IIIB-5 through IIIB-7 are calculations based on Commissioner Larson's correspondence and serve as source tables

TABLE IIIB-1

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant (1980 Dollars)
(30 Year Life)

Cost Component	Cost/Unit	Quantity/Yr.	Cost/Yr.	mills/kwhe
a) Mining and Milling	$20/lb U_3O_8	321,022 lbs U_3O_8	$6,420,440	0.98
b) Conversion to UF_6	$5/kg U	123,456 kg U	$617,280	0.09
c) Enrichment	$97/kg SWU	116,822 kg SWU	$11,331,734	1.72
d) Fuel Prep and Fabrication	$112/kg U	29,021 kg U	$3,250,352	0.50
e) Spent Fuel Shipping	$8/kg U	25,937 kg U	$207,496	0.03
f) Reprocessing	$56/kg U	25,937 kg U	$1,452,472	0.22
g) Reconversion	$2/kg U	25,677 kg U	$51,354	0.01
h) Waste Management	$16/kg U (reactor fuel)	26,739 kg U	$477,824	0.07
i) Shipping				
b) to c)	$.42/kg U	122,839 kg U	$51,592	
c) to d)	$.90/kg U	29,021 kg U	$26,119	
d) to d)	$.72/kg U	28,295 kg U	$20,372	
f) to g)	$1.45/kg U	25,677 kg U	$37,232	
Shipping total			$135,315	0.02
Subtotal			$23,894,267	3.64
j) Fuel Inventory Carrying Charge (at 12%)			$8,672,400	1.32
k) Safeguarding			NA	-
l) Insurance			NA	-
Total (without k and l)			$32,566,667	4.96

Assumptions:
Load factor = .75
Burnup = 30,561 MW(t)D/MTU
Efficiency = 33.5 percent
Inflation rate = 7 percent annually
30 year plant life

Sources: Tables IIIB-3 and III-3.

TABLE IIIB-2

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant (1980 dollars)
(10 Year Operation)

Cost Component	Cost/Unit	Quantity/Yr.	Cost/Yr.	mills/kwhe
a) Mining and Milling	\$20/lb U_3O_8	360,400 lbs U_3O_8	\$7,208,000	1.10
b) Conversion to UF_6	\$5/kg U	138,600 kg U	\$693,000	0.10
c) Enrichment	\$97 kg SWU	124,467 kg SWU	\$12,073,299	1.84
d) Fuel Prep and Fabrication	\$29,679 kg U	29,679 kg U	\$3,324,048	0.50
e) Spent Fuel Shipping	\$8/kg U	26,525 kg U	\$212,200	0.03
f) Reprocessing	\$56/kg U	26,525 kg U	\$1,485,400	0.23
g) Reconversion	\$2/kg U	26,181 kg U	\$52,362	0.01
h) Waste Management	\$16/kg U (reactor fuel)	27,345 kg U (reactor fuel)	\$437,520	0.07
i) Shipping				
b) to c)	\$.42/kg U	137,907 kg U	\$57,921	
c) to d)	\$.90/kg U	29,679 kg U	\$27,711	
d) to d)	\$.72/kg U	28,937 kg U	\$20,835	
f) to g)	\$1.45/kg U	26,260 kg U	\$38,077	
Shipping total	-	-	\$143,544	0.02
Subtotal			\$25,629,373	3.90
j) Fuel Inventory Carrying Charge (at 12%)			\$8,672,400	1.32
k) Safeguarding			NA	-
l) Insurance			NA	-
Total (without k and l)			\$34,301,773	5.22

Assumptions:
Load factor = .75
Burnup = 29,883 MW(t)D/MTU
Efficiency = 33.5 percent
Inflation rate = 7 percent annually
Plant operation = 10 years

Sources: Tables IIIB-4 and III-3.

TABLE IIIB-3

Annual Uranium Flow for A Typical
1000 MWe Light Water Reactor
(30 year life)

		Uranium Kg/Year	Percentage Weight of U^{235}	SWU/Year
Conversion	(in)	123,456	.711	
(0.5% loss)	(out)	122,839	.711	
Enrichment	(regular in)	122,839	.711	
	(recycled in)	25,600	.87	
	(out)	27,026	3.02	116,822
Recycled U		1,995	3.02	
Fuel Preparation	(in)	29,021	3.02	
(2% recycled)	(recycled)	580	3.02	
(0.5% loss)	(out)	28,295	3.02	
Fabrication	(in)	28,295	3.02	
(5% recycled)	(recycled)	1,415	3.02	
(0.5% loss)	(out)	26,739	3.02	
Reactor	(in)	26,739	3.02	
	(out)	25,937	.87	
Reprocessing	(in)	25,937	.87	
(1% loss)	(out)	25,677	.87	
Reconversion	(in)	25,677	.87	
(0.3% loss)	(out)	25,600	.87	
Enrichment	(in)	25,600	.87	

Assumptions:
Load factor = .75
Burnup = 30.561 MW(t)D/MTU
Efficiency = 33.5 percent
Enrichment tails assay = 0.20 percent U^{235}

Sources: Tables IIIB-5 through IIIB-8 and III-9.

TABLE IIIB-4

Uranium Flow for A Typical
1000 MWe Light Water Reactor
(10 year operation)

		Uranium Kg/Year	Percentage Weight of U^{235}	SWU/Year
Conversion	(in)	138,600	.711	
(0.5% loss)	(out)	137,907	.711	
Enrichment	(regular in)	137,907	.711	
	(recycled in)	26,181	.86	
	(out)	27,638	2.97	124,467
Recycled U		2,041	2.97	
Fuel Preparation	(in)	29,679	2.97	
(2% recycled)	(recycled)	594	2.97	
(0.5% loss)	(out)	28,937	2.97	
Fabrication	(in)	28,937	2.97	
(5% recycled)	(recycled)	1,447	2.97	
(0.5% loss)	(out)	27,345	2.97	
Reactor	(in)	27,345	2.97	
	(out)	26,525	.86	
Reprocessing	(in)	26,525	.86	
(1% loss)	(out)	26,260	.86	
Conversion	(in)	26,260	.86	
(0.3% loss)	(out)	26,181	.86	
Enrichment	(in)	26, 181	.86	

Assumptions:
Load factor = .75
Burnup = 29,883 MW(t)D/MTU
Efficiency = 33.5 percent
Enrichment tails assay = 0.20 percent U^{235}

Sources: Tables IIIB-5 through IIIB-8 and III-9.

TABLE IIIB-5

Calculation of U_3O_8 Yellowcake and U^{238}

Required Annually for a Model Light Water Reactor

Assume: Plant size = 1000 MWe
Enrichment tails assay = 0.20 percent U^{235}
Load factor = .75

Feed Required (lbs U_3O_8)	BWR	PWR
Initial core	988,000	844,000
Replacement loadings	288,000	308,000
10 year average	358,000	361,600
30 year average	311,333	325,867

[Assume: 2 PWR's to 1 BWR]

	LWR
10 year average	360,400
30 year average	321,022

Feed Required (kgs U_3O_8)	LWR
10 year average	163,447
30 year average	145,588

Feed Required (kgs U)	LWR
10 year average	138,600
30 year average	123,456

Source: Letter from C. E. Larson, Commissioner, U. S. Atomic Energy Commission, Washington, D.C. 20545, June 27, 1974.

TABLE IIIB-6

Calculation of Separative Work Required

Annually for a Model Light Water Reactor

Assume: Plant size = 1000 MWe
Enrichment tails assay = 0.20 percent U^{235}
Load factor = .75

SWU's Required (kg SWU's)	BWR	PWR
Initial core	239,000	222,000
Replacement loadings	105,000	117,000
10 year average	118,400	127,500
30 year average	109,467	120,500

[Assume: 2 PWR's to 1 BWR]

	LWR
10 year average	124,467
30 year average	116,822

Source: Letter from C. E. Larson, Commissioner, U.S. Atomic Energy Commission, Washington, D.C. 20545, June 27, 1974.

TABLE IIIB-7

Calculation of the Burnup (Irradiation Level)

Rate for a Model Light Water Reactor

(MW(t)D/MTU)

Burnup rate	BWR	PWR
Initial Core	17,000	22,600
Replacement loadings	27,500	32,600
10 year average	26,450	31,600
30 year average	27,150	32,267

Assuming two PWR's to every one BWR the burnup rates for an average light water reactor are:

	LWR
10 year average	29,883
30 year average	30,561

Source: Letter from: C. E. Larson, Commissioner, U. S. Atomic Energy Commission, Washington, D.C. 20545, June 27, 1974.

TABLE IIIB-8

Calculation of the Initial and Subsequent
Fresh and Spent Fuel Assays for
a Model Light Water Reactor
(Percent weight of isotope U^{235})

Fresh Fuel Assay	BWR		PWR
Initial core	2.03		2.26
Replacement loadings	2.73		3.21
10 year average	2.66		3.12
30 year average	2.71		3.18
[Assume: 2 PWR's to 1 BWR]			
		LWR	
10 year average		2.97	
30 year average		3.02	

Spent Fuel Assay	BWR		PWR
Initial core	.86		.74
Replacement loadings	.84		.90
10 year average	.84		.88
30 year average	.84		.89
[Assume: 2 PWR's to 1 BWR]			
		LWR	
10 year average		.86	
30 year average		.87	

Source: Letter from C. E. Larson, Commissioner, U. S. Atomic Energy Commission, Washington, D. C. 20545, June 27, 1974.

SECTION III APPENDIX C: COMPARATIVE FUEL CYCLE COSTS - BOILING WATER AND PRESSURIZED WATER REACTORS

This appendix compares the fuel cycle costs of a model pressurized water reactor with those of a boiling water reactor. The analysis is based on data supplied by Commissioner C. E. Larson, Atomic Energy Commission, referred to in Appendix B. The data supplied specific thermal reactor characteristics essential to the calculation of fuel cycle costs. The methodology is that used previously in this study.

Table IIIC-1 shows the fuel cycle costs for a boiling water reactor (BWR) in 1980 to be 4.99 mills per kilowatt of electric generation (mills/kwhe). For a pressurized water reactor (PWR) these costs were 4.91 mills/kwhe. The fuel cycle costs for the model plant analyzed in Table III-2 were 4.97 mills/kwhe; falling within these bounds.

The differences in costs between the two plant types is small and can be traced to differences in core burnup rates and the required enrichment level of the reactor fuel. A BWR requires more feed at the reactor but, since the enrichment level of the feed is lower than that required for a PWR, the natural uranium requirements are lower.

Tables IIIC-2 and IIIC-3 show the average annual uranium flow required for the fuel cycle processes of both the BWR and the PWR. They serve as source tables for Table IIIC-1. Table IIIC-4 gives the calculations necessary before the standard methodology of this study could be applied to Commissioner Larson's plant characteristics.

The methodology of this study is presented entirely in Table III-9. The changes in methodology that must be made prior to adopting Commissioner Larson's statistics are given at the end of Table IIIC-4. What these changes indicate are the different amounts of recycled fuel enrichment and separative work units employed, given the different plant charac-

TABLE IIIC-1

1980 Fuel Cycle Costs for an Average 1000 MWe Nuclear Power Plant (1980 dollars)

Cost Component	Cost/Unit	Boiling Water Reactor Quantity/Yr.	Cost/Yr.	mills/kwhe	Pressurized Water Reactor Quantity/Yr.	Cost/Yr.	mills/kwhe
a) Mining and Milling	$20/lb U_3O_8	257,489 lbs U_3O_8	$5,149,780	0.90	273,377 lbs U_3O_8	$5,467,540	0.96
b) Conversion to UF_6	$5/kg U	99,023 kg U	$495,115	0.09	105,133 kg U	$525,665	0.09
c) Enrichment	$97/kg SWU	95,514 kg SWU	$9,264,834	1.63	105,884 kg SWU	$10,270,748	1.80
d) Fuel Prep and Fabrication	$112/kg U	27,894 kg U	$3,124,128	0.55	24,182 kg U	$2,708,384	0.48
e) Spent Fuel Shipping	$8/kg U	24,930 kg U	$199,440	0.03	21,613 kg U	$172,904	0.03
f) Reprocessing	$56/kg U	24,930 kg U	$1,396,030	0.25	21,613 kg U	$1,210,328	0.21
g) Reconversion	$2/kg U	24,681 kg U	$49,362	0.01	21,396 kg U	$42,792	0.01
h) Waste Management	$16/kg U (reactor fuel)	25,701 kg U (reactor fuel)	$411,216	0.07	22,281 kg U (reactor fuel)	$356,496	0.06
i) Shipping							
b) to c)	$.42/kg U	98,528	$41,382		104,607 kg U	$43,935	
c) to d)	$.90/kg U	27,894	$25,104		24,182 kg U	$21,764	
d) to d)	$.72/kg U	27,197	$19,582		23,578 kg U	$16,976	
f) to g)	$1.45/kg U	24,681	$35,788		21,396 kg U	$31,024	
Shipping total	-	-	$121,856	0.02		$131,699	0.02
Subtotal			$20,211,811	3.55		$20,868,556	3.66
j) Fuel Inventory Carrying Charge (at 12%)			$8,182,713	1.44		$7,093,898	1.25
k) Safeguarding			NA			NA	-
l) Insurance			NA			NA	-
Total (without k and l)			$28,394,524	4.99		$27,962,454	4.91

BWR Assumptions:
Load factor = .65
Burnup = 27,150 MW(t)D/MTU
Efficiency = 34.0 percent
Inflation rate = 7 percent annually

PWR Assumptions:
Load factor = .65
Burnup = 32,267 MW(t)D/MTU
Efficiency = 33.0 percent
Inflation rate = 7 percent annually

Fuel Inventory Carrying Charges were calculated from Table III-2 as follows:
Assume a reactor using 23,607 kg U fuel annually has a carrying charge = 1.32 mills/kwhe, then the inventory charge for an arbitrary plant using x kg U fuel annually is $\frac{1.32 \text{ mills/kwhe}}{23,607/x}$

Sources: Tables III-3, IIIC-2 and IIIC-3.

TABLE IIIC-2

Uranium Flow for a Typical

1000 MWe Boiling Water Reactor

		Kilograms U	Percentage Weight of U^{235}	SWU's
Conversion	(in)	99,023	.711	
(0.5% loss)	(out)	98,528	.711	
Enrichment	(regular in)	98,528	.711	
	(regular out)	20,058	2.71	73,753
	(recycled in)	24,607	.84	
	(recycled out)	5,918	2.71	21,761
	(out)	25,976	2.71	95,514
Recycled U		1,918	2.71	
Fuel Preparation	(in)	27,894	2.71	
(2% recycled)	(recycled)	558	2.71	
(0.5% loss)	(out)	27,197	2.71	
Fabrication	(in)	27,197	2.71	
(5% recycled)	(recycled)	1,360	2.71	
(0.5% loss)	(out)	25,701	2.71	
Reactor	(in)	25,701	2.71	
	(out)	24,930	.84	
Reprocessing	(in)	24,930	.84	
(1% loss)	(out)	24,681	.84	
Reconversion	(in)	24,681	.84	
(0.3% loss)	(out)	24,607	.84	
Enrichment	(in)	24,607	.84	
	(out)	5,918	2.71	21,761

Assumptions:
Load factor = .65
Burnup = 27,150 MW(t)D/MTU
Efficiency = 34.0 percent
Plant life = 30 years
Enrichment tails assay = 0.20 percent U^{235}
99,023 KgU = 116,775 KgU_3O_8 = 257,489 lbs U_3O_8

Sources: Letter from C. E. Larson, Commissioner, U.S. Atomic Energy Commission, Washington, D.C. 20545, June 27, 1974.
Tables III-9 and IIIC-4.

TABLE IIIC-3

Uranium Flow for A Typical

1000 MWe Pressurized Water Reactor

		Kilograms U	Percentage Weight of U^{235}	SWU's
Conversion	(in)	105,133	.711	
(0.5% loss)	(out)	104,607	.711	
Enrichment	(regular in)	104,607	.711	
	(regular out)	17,940	3.18	84,354
	(recycled in)	21,332	.89	
	(recycled out)	4,579	3.18	21,530
	(out)	22,519	3.18	105,884
Recycled U		1,163	3.18	
Fuel Preparation	(in)	24,182	3.18	
(2% recycled)	(recycled)	484	3.18	
(0.5% loss)	(out)	23,578	3.18	
Fabrication	(in)	23,578	3.18	
(5% recycled)	(recycled)	1,179	3.18	
(0.5% loss)	(out)	22,281	3.18	
Reactor	(in)	22,281	3.18	
	(out)	21,613	.89	
Reprocessing	(in)	21,613	.89	
(1% loss)	(out)	21,396	.89	
Reconversion	(in)	21,396	.89	
(0.3% loss)	(out)	21,332	.89	
Enrichment	(in)	21,332	.89	
	(out)	4,579	3.18	

Assumptions:
Load factor = .65
Burnup = 32,267 MW(t)D/MTU
Efficiency = 33.0 percent
Plant life = 30 years
Enrichment tails assay = 0.20 percent U^{235}
105,133 KgU = 123,980 KgU_3O_8 = 273,377 lbs U_3O_8

Sources: Letter from C. E. Larson, Commissioner, U.S. Atomic Energy Commission, Washington, D.C. 20545, June 27, 1974.
Tables III-9 and IIIC-4.

TABLE IIIC-4

Calculation of Enrichment and Feed Required
Separative Work Units to Produce One Kilogram
of Enriched Uranium with a 0.20 Percent U^{235} Tails Assay

Enrichment Level (% U^{235})	Natural Feed (kg U/kg U Product)	Separative Work (SWU's/kg U Product)
3.0	5.479	4.306
1.40	2.348	1.045
3.18	5.831	4.702
2.71	4.912	3.677
	189 enriched feed	
3.18	4.658	4.702
	.84 enriched feed	
2.71	4.158	3.677

Sources: NUS Corporation, Guide for Economic Evaluation of Nuclear Reactor Plant Designs, Jan. 1969, pp. D.1-6 through D.1-10.
U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase 1, July 31 and August 1, 1973, 1973, pp. 12 and 39.
Table III-9.
Letter from C. E. Larson, Commissioner, U.S. Atomic Energy Commission, Washington, D.C. 20545, June 27, 1974.

Calculations for determing enriched feed:

(1) Kgs of .89 and .84 enriched uranium containing equal weights of U^{235} as one Kg of natural uranium $= \frac{.711}{.89} = .7989$ and $\frac{.711}{.84} = .8464$

Multiplying (1) by the amount of natural feed required gives step (2).

(2) Kgs of .89 enriched feed = .7989 X 5.831 = 4.658

Kgs of .84 enriched feed = .8464 X 4.912 = 4.158

In Table III-9 the calculation changes that must be made with respect to the enriched feed requirements are:

- for a PWR: S = E/4.658
  N = (5.831) X B
  SWU = [B, S or Enr] X 4.702

  for a BWR: S = E/4.158
  N = (4.912) X B
  SWU = [B, S Enr] X 3.677

teristics. The different plant characteristics are stated in terms of required and discharged uranium enrichment levels.

What is necessary for a change in the enrichment criteria are the uranium ratios of slightly enriched recycled uranium to fully enriched uranium feed. The ratios are determined in two steps. First, the amount of discharged uranium that contains an equivalent amount of U^{235} as a kilogram of natural uranium is determined by dividing the natural enrichment level by the discharged enrichment level. Second, this fraction is multiplied by the natural feed that would be required to produce a kilogram of uranium at the lower level. In this process the separative work units are kept constant, where it is assumed that the error thus involved is insignificant. These results are then substituted into the indicated equations.

SECTION III FOOTNOTES

1. Estimates are as follows: mining and milling-1980 dollars, enrichment-1974 dollars, all others-1973 dollars.

2. See footnotes to Table III-3.

3. Atomic Energy Commission, The Nuclear Industry, 1973, WASH 1174-73 (1973), p. 15; and Atomic Energy Commission, Nuclear Power, WASH - 1099, Dec. 1971, p. 134.

4. See Table III-8.

5. U.S. Atomic Energy Commission, Forecast of Growth of Nuclear Power, January 1971, WASH-1139, Table 9, p. 18.

6. A mill is a unit of value equal to 1/1000 of a dollar or 1/10 of a cent.

7. Compare Tables IIIA-2 and IIIA-3. If all factors are held constant except the availability (load) factor, then the difference in cost is less than .05 mills/kwhe.

8. In the literature the burnup rate ranges between 8,208 MW(t)D/MTU and 33,000 MW(t)D/MTU. See: Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH-1099, December 1971, p. 134, Atomic Energy Commission, Current Status and Future Technical and Economic Potential of Light Water Reactors, WASH-1082, March 1968, p. 1-26, and Atomic Energy Commission, Forecast of Growth of Nuclear Power, WASH-1139, January 1971, p. 18. See Table IIIB-7.

9. Atomic Energy Commission, Forecast of Growth of Nuclear Power, WASH-1139, January 1971, p. 18.

10. Compare Table IIIA-1 and IIIA-2, plus IIIA-4 and IIIA-5.

11. Compare with Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH-1099, December 1971, p. 134, and Table III-3.

12. The uranium is lost when uranium in the form of UO_2 is formed into pellets, sintered into a desired density, loaded into Zircaloy or stainless steel tubes, fitted with end cups, welded, and assembled in fixed arrays. Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH-1099, December 1971, p. 134.

13. U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and August 1, 1973, p. 39.

14. Ibid., pp. 12, 13, 39.

15. "Separative Work Units - It is common practice to express capacity and production rate of a uranium enrichment plant in terms of separative work units. A separative work unit is not a quantity of material, but a measure of the effort expended inthe plant to separate a quantity of uranium of a given assay into two components, one having a higher percentage of uranium-235 and one having a lower percentage. Separative work is generally expressed in kilogram units to give it the same dimensions as material quantities, i.e., kilograms or metric tons of uranium. It is common practice to refer to a kilogram separative work unit simply as a separative work unit or as SWU." Atomic Energy Commission, The Nuclear Industry, 1973, WASH-1174-73, p. 42.

16. See Table III-5 and III-8.

17. Atomic Energy Commission, Forecast of Growth of Nuclear Power, WASH-1139, January 1971, p. 18.

18. Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH-1099, December 1971, p. 134.

19. I.e., 0.8365 x 5.479 KgU = 4,583 KgU.

20. Ibid., p. 134.

21. This calculation is based on molecular weights and the conversion tables.

22. Letter from C. E. Larson, Commissioner, U.S. Atomic Energy Commission Washington, D.C., June 27, 1974.

SECTION IV: URANIUM COSTS

A. Uranium Reserves

Reserve estimates are price dependent. As the London *Economist* succinctly states, "The higher the uranium price goes, the larger published reserves become. Reserves are calculated in terms of production costs, when the price justifies a cost increase from the standard $10 a pound to $15, companies tend to find that their accessible reserves double, because there are now more 'accessible' areas (i.e., areas that it is economic to mine)."[(1)]

Several reserve and resouce estimates are available. For the U.S., one of the most general can be derived from U.S. Geological Survey data. This is presented in Table IV-1. In the table, the identification of the resource by type is based on the assumption of an $8 cost. The tonnages quoted include not only economically recoverable reserves, but resources which are not recoverable at that price. If, for example, the basic cost was $10, identified submarginal resources (at an $8 base) become identified recoverable resources. Finally, the price base used in the table refers, not to the mine price for ore, but to the concentrated ore price at the mill; the yellowcake price.

The inclusion of uranium recovery from phosphate rock is based on a process which has now become commercial. The rock is processed into phosphoric acid (a base for high potency fertilizer production); the uranium is removed during processing. Gulf Research and Development, using a recovery process based on an AEC laboratory scale process, is demonstrating a mobile pilot recovery plant. The plant, mounted on two enclosed truck trailers, can be moved to various phosphoric acid production facilities.[(2)]

TABLE IV-1

U.S. Uranium Resources and Reserves (1972)

Price/Pound U_3O_8	Short Tons	Short Tons (Cumulative)	Identification ($8.00 per pound base)
≤$8.00	250,000	250,000	Conventional, identified recoverable resources (± 20 percent)
≤$10.00	50,000	300,000	Conventional, identified submarginal resources.
$10.00 - $15.00	150,000	1,450,000	Conventional, identified submarginal resources.
	1,000,000		Identified, paramarginal resources from phosphate rock.
>$20.00	500,000	6,950,000	Undiscovered, conventional resources in known districts.
	5,000,000		Identified submarginal resources from phosphate rock.

Source: P.K. Theobald, et al, in U.S. Geological Survey, Energy Resources of the United States, Circular 650, 1972, pp. 23-24.

Note: Undiscovered conventional recoverable resources in known districts (500,000 tons) and undiscovered conventional submarginal resources in known districts (400,000 tons) are both subject to an error factor of 2; they may be twice as large or only one-half as large.

On a more ambitious scale, the Uranium Recovery Corporation, a subsidiary of United Nuclear Corporation, is building a fully commercial plant to recover uranium from phosphate rock. The output is rated at 1000 tons per year. Production is scheduled on or after 1974. The technology was established in the mid-1950's, but the $15-20 per pound price range was uneconomic. The plant is located in Florida where it is estimated that the area potential is currently 2000 tons per year rising to 70,000 tons per year by the year 2000.[3] A second facility is planned with construction due to begin about 1975.

Because uranium and phosphoric acid are joint products recovered from phosphate rock, the cost of both are partially dependent on the production and sale price of each. As the price of fertilizer increases, on a joint cost basis, the cost of producing uranium may decrease. Alternatively, as the price of uranium rises and more is produced from phosphate rock, the cost of production allocated to phosphate fertilizers may decline.

Limiting the discussion to conventional sources of uranium, many areas of the U.S. have not been explored.[4] Furthermore, the AEC has acknowledged suggestions that its estimates of potential uranium resources may be too conservative. Currently, it is taking steps to broaden the base of knowledge of the undiscovered resources.[5]

The AEC estimates conventional uranium reserves yearly. Table IV-2 shows domestic reserve-resource estimates in relation to cut-off cost levels. These are maximum costs below which the ore is considered exploitable. The reserve category of resources refers to deposits that have been quantitatively measured and qualitatively analyzed. The estimated additional resources category refers to appraisals of the amount of undiscovered uranium the existence of which is sur-

TABLE IV-2

Cumulative U.S. Uranium Resources[(1)]
(thousand short tons U_3O_8)

Cut-off Cost ($/lb. U_3O_8)	Reserves	Estimated Additional	Total
8	275	450	725
10	340[(2)]	700	1040
15	525	1000	1525
30	665	1650	2315
50	6000	4000	10000
100	12000	13000	25000

Source: Atomic Industrial Forum, Nuclear Industry, March 1974, p. 7, and Atomic Energy Commission, Potential Nuclear Power Growth Patterns, WASH-1098, December 1970, pp. 2-11.

Notes: (1) Uranium estimates at cut off costs less than $15 as of January 1974. Uranium estimates at cut off costs from $15-$100 as of January 1970.

(2) 90,000 additional tons may be available as a by product of phosphate and copper production through the year 2000.

mised on the basis of probabilistic geological evidence. This category corresponds to potential reserves.

By the end of 1972, the AEC estimated reasonably assured reserves, recoverable at no more than \$8 per pound (for yellowcake), at 273,000 tons with potential reserves at the same price yielding an additional 450,000 tons.(6) In 1973, a net addition to reserves of 2000 tons was made. Gross additions to reserves was 21,000 tons. Subtracting 14,000 tons of deliveries yields a net of 7000 tons added. However, 5000 tons were reclassified out of the \$8 class. Some of this was due to additional costs and some was due to the practice of mining the highest grade ore and leaving the rest in the spoil banks where it may be irretrievable.(7) This latter form of loss can only be considered a waste of a reportedly very scarce resource.

As of January 1, 1974, uranium ore reserves, producible at a cut-off cost of \$8 per pound U_3O_8, were estimated at 275,000 short tons. An additional 450,000 tons of uranium recoverable at \$8 per pound U_3O_8 were hypothesized. At \$15 per pound U_3O_8, the reserves and estimated additional resource categories indicate 525,000 and 1,000,000 tons respectively. Data for uranium resources in higher cost brackets are available only for 1970. In the past, there has been little incentive to evaluate uranium resources at cost levels in excess of \$30 per pound U_3O_8. These estimates are considered both crude and conservative.

The vast majority of known domestic resources of uranium are concentrated in the western part of the U.S.; specifically in the Colorado Plateau and Wyoming Basin regions. Table IV-3 gives a 1972 AEC estimate of resources confined to this sector.

Recent world wide interest in nuclear power has caused an increase in uranium exploration. Early results of

TABLE IV-3

Cumulative AEC Estimates of Uranium Resources in Western United States (as of 1/1/72)

(thousand short tons U_3O_8)

Cut-off Cost ($/lb. U_3O_8)	Reserves	Estimated Additional	Total
8	NA	460	NA
10	333	650	983

Source: Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1, 1972, pp. 17, 24.

this exploration are shown in Table IV-4. It can be seen that over a four year period total resources estimated to be available at costs up to \$10 per pound U_3O_8 increased from 1,720,000 to 2,300,000 tons. Significant increases occurred in the U.S. and Australia. It must be emphasized that uranium exploration in the rest of the world is at a much earlier stage than U.S. exploration. It is likely that much more uranium will be found.

Estimates of uranium resources in the U.S.S.R. plus China are reported to be at least equal to those of the U.S. plus Canada. If, therefore, one takes 1,500,000 short tons as the estimate for the latter two countries (at a \$10 per pound cut-off) and assumes a distribution of phosphate rock similar to that of the U.S., then if the U_3O_8 price becomes \$20 per pound, the estimate of world resources excluding the East Bloc increases from 2,300,000 tons to at least 11,109,000 tons. Including the East Bloc increases the total to 18,354,000 tons.

According to the International Atomic Energy Agency, world wide exploration is down due to low prices. However, they estimate that reasonably assured resouces (reserves) are about 1,126,000 tons at a price not greater than \$10 per pound. Additional resources at that price are estimated to be 1,192,000 tons.[8]

Canada, one of the major producers, has a stockpile of U_3O_8 that is still growing. At current prices and a soft market due to low demand, mines and mills are operating below capacity. Both government and utility planners are reserving a large block of low cost reserves for domestic use. Little exploration is being conducted now. According to the Canadian Department of Energy, Mines and Resources, at a price of not more than \$15 per pound producible resources are estimated at 400,000 tons of U_3O_8. They estimate cumu-

TABLE IV-4

Estimated World Resources of Uranium Available at Costs Less than $10/lb. U_3O_8

(thousand tons)

	1970 Estimates				1974 Estimates		
	Reserves	Estimated Additional	Total		Reserves	Estimated Additional	Total
Argentina	10	22	32				
Australia	22	7	29	- - - - - - -	140	48	188
Brazil	1	1	2				
Canada	232	230	462	- - - - - - -	241	247	488
Central African Republic	10	10	20				
France	45	25	70	- - - - - - -	47	31	78
Gabon	14	6	20	- - - - - - -	26	6	32
Italy	2		2				
Japan	3		3				
Mexico	1		1				
Niger	26	39	65	- - - - - - -	52	26	76
Portugal	10	8	18				
South Africa	200	15	215	- - - - - - -	263	10	273
Spain	11		11				
U.S.A.	250	510	760	- - - - - - -	340	700	1040
Others (non-Communist)	4	11	15	- - - - - - -	68	69	137
Total (Rounded)	840	880	1720		1180	1140	2300

Sources: 1970 estimates: European Nuclear Energy Agency and the International Atomic Energy Agency, Uranium Resources, Production and Demand (Organization for Economic Cooperation and Development), September 1970, p. 11.

1974 estimates: Atomic Industrial Forum, Nuclear Industry, March 1974, p. 7.

lative Canadian demand to the year 2000 at about 100,000 tons with an additional 60,000 tons committed to exports. There is, therefore, a significant surplus of low to medium cost resources proved or indicated. The Department estimated that if Canada was to keep 20 percent of the world market, current production of 5000 tons per year would have to increase to 14,000 tons per year in 1980.(9)

Australia has a surplus of low cost U_3O_8. Resources far exceed reserves. It is reported that at a price of $6 per pound for concentrate, recovery costs, even in remote areas with their concomitant problems, are low enough to make operation profitable.(10)

In the Republic of Niger, one mine is already rated at 600,000 metric tons per year. Two mills are due for completion in 1976-77. Their combined capacity is rated at 3500 metric tons metal equivalent per year.(11) Finally, huge but undeveloped deposits have been found in South-West Africa.(12)

Reserves and resources are positively located only by drilling. Two types of drilling may be identified: exploratory and developmental. The former locates a new area or extends an old area in a new direction. The latter defines the extent of an area, gauges the quantity of the reserve on a preliminary basis and provides the information needed for planning a mine.

The record of drilling in the U.S. is shown in Table IV-5. The early exploratory peak was reached in 1956-57 while the associated development drilling peak occurred in 1960. Subsequently, exploratory drilling peaked again in 1968-70 with a development drilling peak in 1969. There is some confusion concerning present operations. In comparison with Table IV-5, 17 million feet of drilling was planned for 1973, 29.1 million feet was planned for 1974, and 33.7 million feet is planned for 1975.(13) In the period 1958-1967,

TABLE IV-5

U.S. Exploratory and Developmental Drilling, 1948-1972

Year	(1) Exploratory Drilling (mil. feet)	(2) Development Drilling (mil. feet)	(3) Column (2) Divided by Column (1)
1948	.170	.040	.24
1949	.360	.053	.14
1950	.570	.208	.36
1951	1.080	.348	.32
1952	1.365	.300	.22
1953	3.648	.367	.10
1954	4.057	.553	.14
1955	5.267	.762	.14
1956	7.287	1.503	.21
1957	7.352	1.848	.25
1958	3.759	3.494	.93
1959	2.368	3.282	1.39
1960	1.399	4.211	3.01
1961	1.319	3.190	2.42
1962	1.483	2.431	1.64
1963	.880	1.977	2.25
1964	.967	1.245	1.29
1965	1.164	.949	.82
1966	1.800	2.400	1.33
1967	5.450	5.350	.98
1968	16.200	7.600	.47
1969	20.500	9.400	.46
1970	18.000	5.500	.31
1971	11.400	4.100	.36
1972	11.800	3.600	.31
1973	13.900	4.600	.33
1974	15.200	5.100	.34

Source: Atomic Energy Commission, Uranium Exploration Expenditures in 1972 and Plans for 1973-74, May 1973, figure 2.

Notes: (1) 1973-1974 are estimated.

(2) Exploratory drilling includes the search for new deposits and extensions. Development drilling is needed for mine planning.

development drilling in previously explored areas almost equalled or exceeded exploratory drilling.[14] It was the major factor in the reserve increase at that time. However, the reduced level of exploratory drilling meant that uranium resources, which could later be developed, were not being actively searched out.

In part because of the lack of new areas, ore quality declined. In terms of the ore grade processed (percent of U_3O_8 per tons of ore milled), the grade of ore milled declined steadily from 0.26 percent in 1963 to 0.20 percent in 1969. It rose to 0.21 in 1971 and 1972. This means that to bring one ton of U_3O_8 to the mill in 1963 required that a total of 384.6 tons of uranium bearing ore be brought to the mill. In 1972, the number of tons that had to be taken to the mill was 476.2. Additionally, the recovery of U_3O_8 from the ore processed by the mills also declined. In the period 1963-1967 the percentage of contained U_3O_8 recovered from the ore was about 95 percent. This fell to just over 93 percent by 1972. Together, these two factors mean that to get ore for yellowcake in 1963 required the delivery of 404.8 tons of ore to the mill. By 1972 this had risen to 512.0 tons.[15]

In large measure, the record shown in Table IV-5 is an outgrowth of AEC policies. First, subsidization of exploration and milling plant construction; second, uranium purchase policies; and third, ore prices.

In the early years, the AEC contributed $25,000 per mine, subsidized discovery and maintained prices with government purchases. To this day, the depletion allowance for uranium is 22 percent, as it is for oil, rather than the five percent allowed for coal.

A measure of the support given to mining and milling can be seen in Table IV-6. The table shows the ratio of AEC

TABLE IV-6

Non-AEC Uranium Purchases as a Percent of Total Uranium Ore Receipts

Year (1)	Percent
1948	24
1949	62
1950	78
1951	75
1952	61
1953	49
1954	45
1955	47
1956	80
1957	94
1958	97
1959	98
1960	97
1961	99

Source: Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1973, pp. 7, 14.

Note: (1) AEC purchases are for fiscal years, total ore shipments are for calendar years.

purchases of uranium at buying stations and under special arrangements compared to total uranium ore receipts at buying stations and mills. The table is only approximate as the AEC purchases are reported for fiscal years while shipments to mills are reported for calendar years. The closer the percentage is to 100, the less is the AEC involvement.

AEC purchases of uranium ore peaked in 1956.[16] Between 1949 and 1962 the AEC purchased 2.992 million tons of ore plus an additional 0.631 million tons bought under special arrangement from the mills while they were under construction. The total of 3.623 million tons was sold back to the mills by 1966. The buying program ended in 1962. On the whole, this represented an augmented cash flow to the companies involved.[17]

AEC concentrate (yellowcake) purchases were high for the period 1959 1963 with the peak between 1961 and 1962. Perhaps more important, the AEC paid a price of over $10 per pound of concentrate for the entire period from 1951-1957. The high was $12.35 per pound in 1953. Subsequently, it fell steadily to $5.54 per pound by 1971.[18]

As of January 1973, the characteristics of U.S. ore reserves in the $8 per pound category could be described as follows: the median grade of ore contained 0.221 percent U_3O_8 per ton of ore, the median depth of deposits was 350-400 feet, the median ore thickness was 9-10 feet and the median size of the ore deposit was 1-2.5 million tons. Drilling depth, both exploratory and for development were increasing. In 1958 the average was 150 feet, by 1972 it was 421 feet.[19] In terms of production, the median mine depth was 350-400 feet.[20]

B. Uranium Prices

There does not appear to be any long run shortage of uranium ore. Therefore, it is necessary to find some explanation for the following observed price behavior.

In 1972 inventories of yellowcake were estimated to be 20 million pounds with potential production through 1975 exceeding unfilled requirements by over 8 million pounds. It was reported, on the basis of the expected rate of utility construction, that the situation would level out by 1976 and that future shortages would develop. Obviously, with the stretchout of construction this has not yet developed. Since 1968, when the AEC was about to terminate purchases, prices for future delivery had been falling. Spot prices for immediate delivery from 1969-1972 were in the range of \$6-\$6.25 per pound but were expected to rise to \$8-\$8.25 per pound by mid-1977.(21) In response to a tender for the Washington public power supply, the following bids were received:(22)

for U_3O_8

1972 delivery - \$6.10-\$6.50/lb.
1975 delivery - \$7.57-\$8.25/lb.
1976 delivery - \$7.73-\$8.50/lb.
1977 delivery - \$7.95-\$9.00/lb.

for UF_6

1972 delivery - \$18.60/kg U
1975 delivery - \$20.45-\$20.80/kg U
1976 delivery - \$21.00-\$26.15/kg U

At the time, domestic prices were generally above world prices.(23)

By the end of 1973, the situation had changed. The response to a TVA bid invitation included only three offers from U.S. suppliers. Prices quoted for 1979 delivery were upward from \$12 per pound with only one-third of the offering covered. TVA was reportedly considering a negotiation ap-

proach. This would undoubtedly mean even higher prices. According to AEC data, past prices for 1980 delivery were about $7.80 per pound, in 1973 dollars, with then current contracts for 1980 delivery in the $11-12 range, excluding escalation. Both producers and the AEC were pointing out that only a small number of firms control large quantities of uncommitted reserves for which production costs could be estimated. Therefore, the producers wanted either a cost-plus type of contract or prices high enough to cover pessimistic supply price estimates. It was noted that producers were holding back supply in the speculative expectation of price increases.(24) By early 1974, Business Week noted that the current price was $7 per pound but that price expectations for the mid-1980's was $15-20 with some talk of $30 per pound for yellowcake. They pointed out that the industry had produced 13,000 short tons of concentrate in 1973, but only 7400 tons had been sent to enrichment plants. While uranium was in substantial surplus, there was no hurry to enter into contracts, the market was almost entirely a futures market.(25)

In August, 1974, the Wall Street Journal reported that the United Nuclear Corporation had contracted to sell 1.8 million pounds of concentrate over a three year period beginning in 1977. The price was $2.8 million with a $3.6 million advance payment. They noted that such advance payments are being written into contracts with increasing frequency.(26) Excluding the cost of money on the advance payment, the contract calls for $15.56 per pound.

Finally, recent spot prices are reported to be $12 per pound. This is a doubling over the past year. Producers argue that they must redouble if they are to receive a favorable return on their investment.(27)

The results are quite consistent with oligopoly behavior. Price analyses are made difficult because quotations are confidential, even the AEC is excluded. However, the FPC may soon require that they be made public. Even then it may not be easy to translate quotations to a common dollar basis because of ancillary conditions.[28] However, the utilities must be making at least partial translations in order to compare offers.

On an open market basis, Dennison Mines of Canada contracted a sale of 20,000 tons to Tokyo Electric Power. Deliveries at the rate of 2000 tons per year are to start in 1983. The value of the contract was reported to be $800 million including a $10 million down payment.[29] Assuming an interest rate of six percent for ten years on the down payment, the apparent cost is $20.19 per pound for the yellowcake.

The unwillingness of producers to make quotations can be seen in the response to the recent TVA tender. Invitations to bid were extended to over 50 foreign and domestic suppliers for an order of 43,000 tons. Delivery was to start in the 1980's and extend into the 1990's. There were very few bids although this time suppliers were asked to state their own terms.[30]

Finally, the Canadian company, Rio Algom, contracted to sell a total of 10,000 tons of U_3O_8 at the rate of 1000 tons per year starting in 1982 to British Nuclear Fuels. The price was subject to escalation, with the starting average set at $20 per pound. In the mid-1960's the same two companies contracted at about $6 per pound.[31]

C. Uranium Pricing Factors

Given the reserve-resource estimates for the U.S. and the rest of the world, some explanations, if only as hypotheses, of the price behavior are needed. Possible explanations are: demand greater than supply at current prices, lack of competition in the domestic producers' market, cartelization in the rest of the world, and specific actions and implied goals of the AEC.

1. Demand

In 1971, the uranium market was described as soft. Commercial prices were depressed and exploration was curtailed. A shelf price of $8 per pound and escalation from 1972 was expected with the government (AEC) surplus expected to remain off the market until about 1980. With exploration curtailed it was thought that supplies would be inadequate to meet the expected surge in demand due in the late 1970's and early 1980's. Hence, prices would rise.(32)

Part of the market softness at that time was explained by the action of the electric utilities. Reportedly they were contracting forward for 76 percent of the UO_2 necessary for their initial cores but only 39 percent of their fourth reload. This was due to doubts about construction and operating schedules.(33)

The price problems existed into late 1973. There was a free market but power schedule slippages resulted in a short-term pile up of U_3O_8 inventories. Future prices might have gone down but for the embargo on imports and the regulations concerning plutonium recycle.(34)

By December, 1973, Nuclear Industry was reporting a rapid increase in medium to long-term contracts which started in June. Utility requirements were not covered for

more than a few years. They could get few replies to bid invitations and supply negotiations were reported, "...which practically guarantees the producer a 'reasonable' profit." The import embargo remained.[35]

Estimates of annual domestic uranium requirements made by the AEC, assuming a 0.3 percent tails assay for enrichment were:

1973 - 10,000 tons U_3O_8
1975 - 18,200 tons U_3O_8
1980 - 38,500 tons U_3O_8
1985 - 71,500 tons U_3O_8

Cumulating from 1973 through 1985 yields 474,200 tons of U_3O_8.[36] Between 1973 and 1990, production was expected to total 902,000 tons. However, by adding an eight year reserve in 1990 of 1,086,000 tons, the cumulative total amounts to 1,988,000 tons. It was argued by the AEC that the desired level of potential resources in 1990 should be 2,664,000 tons. When added to production and reserves, this amounts to 4,652,000 tons.[37] Based on Table IV-1, this corresponds to a 1972 based supply price of $15-20 per pound.

Based on the AEC data, Nuclear Industry forecast a current need for 14,000 tons per year with 120,000 tons per year needed in the 1990's.[38] A more detailed forecast of concentrate requirements was made by the AEC in 1973 for the period 1973-1985. If the tails assay at the enrichment plant was assumed to be 0.20 percent, concentrate requirements totalled 391,000 short tons of U_3O_8, at a tails assay of 0.25 percent it was 428,100, at 0.30 percent it was 474,100 short tons of U_3O_8. The AEC noted that for the two higher tails assays the added enrichment would come from the AEC stockpile.[39] It may be noted that the AEC non-military stockpile was reported to be 38,000 tons of concentrate in March, 1974, and was expected to be used up by 1978.[40] By September, the stockpile was reported to be only 25,000 tons.[41]

The AEC forecast can be translated into mining requirements. Assuming the current 93 percent recovery at the mill (1972) and a 0.21 percent of U_3O_8 in the mill feed, at a 0.20 percent tails assay 200.2 million tons of ore must be delivered to the mills, at a 0.25 percent tails assay 219.2 million tons must be delivered, while at a 0.30 percent assay 242.8 million tons must be received.

Short-term supply problems were expected due to an eight year lead time between exploration and the construction of milling capacity. It was reported that as producers needed adequate prices to cover exploration, development and profits, utilities and the government could help finance exploration and development.(42)

While demand estimates are usually made on the basis of light water reactors, the development of which was AEC supported, demand would be reduced somewhat if high temperature gas cooled reactors (HTGR) were utilized. The AEC has only recently contributed a relatively small amount to their continued development. The initial R and D funds were private. For an HTGR with direct cycle gas turbines, the plant efficiency is 37 percent compared to only 33 percent for a light water reactor. The efficiency approaches 50 percent if a bottoming cycle using the reject heat from the helium turbine cycle is utilized. With lack of intensive support, the first commercial service is expected no earlier than 1985.(43)

In the foregoing review one critical element has been omitted: the price and availability of competing fuels. Nuclear power is limited to electric utilities and a few military and demonstration propulsion units. In utilities it competes with coal, residual fuel oil and natural gas. In propulsion it competes with diesel fuel oil.

Prices of natural gas have been controlled by government fiat. The result has been that for existing contracts the price is relatively low. For new contracts, if supplies are unavailable, the price may be considered infinite.

The use of coal has been limited by air pollution control regulations and the relative lack of government support for stack gas scrubbers, liquefication and gasification research and development compared to the support levels for nuclear power. Low sulfur coal is in short supply. Its price includes the scarcity factor and the cost of transportation. The latter is high given the distance of western coal from the major consuming markets.[44]

The price of residual fuel oil reflects the current price of crude oil and the greater returns derived from minimizing the output of residual oil by increasing the output of the other fuel components contained in a barrel of crude. The percentage of residual oil produced from a barrel of crude in the U.S. has been falling slowly but steadily. The need to desulfurize the oil has increased its price. While it does not appear likely that crude oil prices will remain at present levels in the absence of the consuming countries effectively ratifying some form of world price stabilization agreement, there is a question of supply security. Protective measures would add to the costs.

Diesel oil is essentially the same as No. 2 home heating oil. Demand for the latter has been rising as home owners, utilities and industry seek to offset the shortage of natural gas.

Government policy has not been antagonistic to high international oil prices. The higher are such prices, the greater the price umbrella over high cost domestic oil, over U.S. coal and over nuclear power. It must be noted, however,

that the prices of foreign and domestic competing fuels is alien to the supply-demand arguments of the AEC and the uranium producers. As seen above, their arguments are couched in terms of the supply and anticipated demand for uranium alone. The competing fuels argument suggests that the price of uranium can be high because the price of other fuels is high. This would be true even if the costs of uranium production were very low. The AEC-producer argument is that uranium prices must be high if we are to get more of it. The current world surplus of low cost uranium is a factor against which the industry must be protected.

2. Competition

The lack of competition in the uranium market has been alluded to above. The bottleneck in the U.S. appears to be in the number of uranium mills which concentrate the ore.

However many independent mining operations exist, the ore is concentrated in relatively few milling plants. Virtually all of these are also engaged in mining operations. Table IV-7 shows the size and identity of these firms. Of the total of 16 firms, the largest eight account for over 77 percent of the nominal milling capacity in the U.S., the largest four account for almost 52 percent.(45) The situation is best described as oligopolistic. One would expect an absence of individual price competition.

Part of the problem can be traced to AEC policies. In 1972 a new lease sale was announced for the Urvan Belt in western Colorado. The Belt came into existence when the AEC was paying up to $12.37 per pound for U_3O_8 concentrate. High quality ore was plentiful and five mills were operating in the area. Four of these were closed in 1962 along with some 40 mines when the AEC ended its initial procurement program.

TABLE IV-7

U.S. Milling Capacity, 1972

Company	Nominal Capacity (tons of ore/day)
Kerr McGee	7000
United Nuclear - Homestake	3500
Anaconda	3000
Union Carbide	3000
Utah International	2400
Exxon	2000
Susquehenna - Western	2000
Continental Oil - Pioneer Nuclear	1750
Atlas	1500
Petrotomics	1500
Western Nuclear	1200
Federal - American	950
Mines Development	650
Dawn Mining	500
Rio Algom	500
Cotter	450
	31900

Source: Atomic Industrial Forum, Nuclear Industry, February 1973, p. 53.

Subsequently, the remaining mill was operating at about one-half capacity in a relatively soft market on low quality ore. Lease sales at that time were made on the basis of negotiation and on AEC contract. The new lease sale was to be on a cash bonus basis. The extent of the deposits in the new extension were not accurately known as only a small part had been subject to development drilling. It was hoped that 40 mines would be reopened and 40 new mines started.[(46)] The timing is important as it takes about six years to explore, three years to open a mine and two years to open a mill. With overlaps, this amounts to about eight years. Initially, milling would not be in short supply as there is excess capacity.

Price, in the absence of AEC contracts, has also been a problem. During 1972, it was argued that a price of $10.40 was necessary to recover ten percent on capital invested in mining and milling if the producing cost was $7.25 per pound of concentrate (yellowcake).[(47)] On this basis, given past prices, an oligopolistic industry would be expected to reduce output and exploration even more than a competitive one.

On the international market, Nuclear Industry reports evidence of a supply cartel with South African, French, Canadian and Australian membership. They cite a decline in the number of firm quotes available for post-1980 delivery. Members only offer options to buy with prices to be negotiated later and an agreement to raise prices for late 1970's delivery.[(48)] In Australia, a probable major producer in the future, the government appears to be controlling exports in order to maintain prices.[(49)] The Canadian government, citing increased demand and increased world prices, has announced a series of measures restricting exports. These include restriction of export contracts to a ten year duration

with a possible five year extension subject to price renegotiation and possible recall, the use of the domestic market as a price floor for exports, supply contract requirements for Canadian utilities and producers, disposal of the government stockpile only on a short-term basis and only to domestic companies, and limitations on the ability of importers to re-export Canadian uranium without prior approval.[50] While some of these restrictions may simply be "Canada first" requirements, others are clearly an attempt to prevent market arbitrage.

Canadian reserve estimates in 1972 were 400,000 tons (exploration ended in the 1960's) with 1973 production set at only 5000 tons. Future needs were quoted at about 80,000 tons for the 15,000 megawatt capacity of Canadian reactors slated for 1984. An additional 73,000 tons were contracted for export to Japan, England and others over the same period. This would imply an excess reserve for the period of 247,000 tons. However, the reserve set aside is for 30 years (2004) and could use up the entire current reserve.[51]

In a short summary, the London Economist describes the current worldwide rush for uranium reserves in Klondike terms. But it warns that potential host governments are guarding reserves as if they were oil. They link increased future uranium prices to oil prices and new nuclear construction programs. Previously low prices are explained as a result of lack of demand.

Some of the new companies entering into exploration contracts are Continental Oil, Compagnie Francais des Petroles and Rio Tinto-Zinc. While reserves and resources should rise as a result of the activity, host governments are expected to claim a larger share of the take.[52]

3. <u>Government Options</u>

By its activities the AEC has an effect on uranium prices.

a. <u>AEC Stocks</u>

In 1972, the AEC had a stock of 50,000 tons of U_3O_8. Rather than auction this off, thereby reducing the price or maintaining a low one, the AEC elected to run down the stock slowly. The method used is to specify a low transactions tails assay for enrichment, use a considerably higher assay for operations, and make up the increased fuel requirement out of its stocks. For example: the value of the enriched uranium charged to the customer (transactions basis) is composed of (1) the units of fuel needed by the customer plus (2) the number of separative work units purchased by the customer. However, the AEC enrichment plant fills the order on the basis of the operating tails assay. This, too, is composed of two parts: (3) the amount of U_3O_8 actually used by the AEC to manufacture the enriched uranium plus (4) the number of separative work units actually used in the enrichment process. It should be noted that (4) is less than (2). This requires (1) to be greater than (3). However, the difference is made up not by additional U_3O_8 but rather by the amount of fuel withdrawn from the AEC stockpile. The value of this is recovered in the unit charge for separative work.

Until June 30, 1973, the AEC used a 0.3 percent tails assay for enrichment while the customer supplied feed on the basis of a 0.2 percent assay. Subsequently, while the transactions assay remained at 0.2 percent, the operating assay dropped to not less than 0.275 percent. Thus, the enrichment customer slowly buys the surplus and the AEC avoids the open market. The stockpile was expected to last until the

end of fiscal 1982. Currently, it is expected to be used up before 1978.

In the explanation of its pricing policy for the stockpile, the AEC is a model of rectitude. Based on a 0.275 percent actual tails assay and the then current enrichment price of $32 per SWU, there are two components. First, the 50,000 tons U_3O_8 equivalent surplus should yield the commercial U_3O_8 price, year by year, until 1982. This would be based on AEC records of actual prices plus its estimates of prices for sales yet to be made. This information is not public. It may be noted that the commercial prices in the early stages of the stockpile disposal were considerably below the $10-12 per pound that AEC originally paid, even without consideration of inventory costs. Therefore, an AEC loss or customer subsidy may exist until the late 1970's. Second, the AEC adds on the cost of conversion of U_3O_8 to UF_6. This cost is classified.(53)

b. <u>Embargo</u>

The embargo on foreign uranium supplies is based on the AEC refusal to enrich foreign uranium for use in domestic reactors. As long as foreign enrichment facilities are inadequate, this is tantamount to an embargo on foreign uranium in general. The AEC proposes to enrich foreign uranium in 1977 for domestic use. However, this would be limited to ten percent of the enrichment customer's requirements. The remainder is reserved for domestic producers. The embargo is slated to disappear after 1984 when higher prices are expected and the AEC stockpile has been exhausted.(54) This, however, is no more than a current plan.

The arguments for and against the embargo are as traditional as the results. (1) There is an oversupply of uranium in both foreign and domestic markets. It is expected

to last no later than the 1980's but meanwhile the embargo is needed to help domestic producers, i.e., raise prices. (2) Small producers need access to land, capital and a market. (3) Foreign imports would allow the enormous foreign reserves to pre-empt the domestic market with concomitant high security risks. Foreign producers could sell uranium in the U.S. at the price of $8 per pound while domestic producers in meeting the price would (by poor production management) irretrievably lose hundreds of millions of pounds of associated $10-15 per pound reserves in operating mines.

The similarity of this argument to that raised in 1959, at the time of the imposition of mandatory oil import controls, should be especially noted. It should also be recalled that while prices rose and the domestic market was protected for the small producers, exploratory drilling and reserve additions slowed as domestic companies moved overseas. Even the line-up is similar: consumers want the embargo lifted, some producers would rather substitute subsidies, while buyers and domestic producers with foreign production sound just like their oil counterparts during the first hearings on the oil embargo. Additionally, the risk factor for uranium is not of the same order of magnitude that it is for oil. Safety margins can be bought at the cost of stockpiling. The AEC has already shown how to maintain a supply equivalent to 50,000 tons of U_3O_8. Finally, the plea for the small producer should be looked at carefully. Again, it is standard in the oil industry. Are these small producers, upon whose welfare all policy devolves, kin to the legendary widows and orphans who own stock? Are they the counterparts of the 4006 coal mines (71.5 percent of the total) which produced only 9.9 percent of the 1970 output?(55) When referring to the basis of uranium price increases, the AEC-producer argument indicates the lack of importance of the small producer. A

few firms control large quantities of uncommitted reserves where production costs can be estimated.(56)

In the debate on the embargo, Canadian producers hoping to sell to the U.S. insisted that they wanted either payment at world market prices at the time of delivery or a negotiated price with a price floor to provide downside protection to support capital expenditures. (The latter is close to the argument of the Texas Railroad Commission for oil.) The development of a world price is noted as a mark of the "coming maturity" of the uranium industry. In the context, what was meant is essentially a cartel supported by producing and consuming country governments. The same is currently being suggested to maintain oil prices.

The success of the cartelization, reduction of domestic competition, embargo and stockpile disposal can be seen in the lack of responses to current bid solicitations. There is no lack of a market to account for the unresponsiveness. Spot prices during the period from 1968-1972 averaged \$5.75-\$6.00 per pound. Buyers do not want to pay \$8 prices much less \$10-11. But at these prices, producers report little incentive to explore or add new capacity. Given the current situation, it pays to speculate on future prices by holding on to current reserves. In this, producers are backed by the embargo and the absence of competing fuels: coal because of air pollution control regulations and the lack of support for stack gas scrubber development, and oil due to price and the shortfall in domestic refinery capacity. It remains to be seen how permanent are these conditions.(57)

c. The Breeder Reactor

Elsewhere in this study it is shown that the AEC has consistently underestimated future nuclear power costs. This leads to low quotations of consumer power costs in terms

of mills per kilowatt hour. It also makes nuclear power appear very competitive. Only in the area of uranium is the AEC prepared to support and ratify higher prices. While it is true that these increased fuel prices can be pushed through directly to the electricity consumer via fuel adjustment clauses and that the net effect on the electricity bill is relatively small, this represents a reversal of the whole thrust of AEC actions and implied goals. A consistent explanation can be made in terms of the shift in AEC emphasis from light water reactors to the liquid metal fast breeder reactor. The explanation is, in part, bound up with national honor. The U.S.S.R.'s BN350 reportedly achieved criticality in October, 1972. It is rated at 350 MWe gross. In France, the Phénix reactor (250 MWe) was due to achieve criticality in August or September, 1973. In the U.K. the PFR reactor is due soon and the SNR300, supported by West Germany-Benelux, is due in 1979.[58] Our own demonstration reactor will not be ready until the mid-1980's.[59]

The relationship between a breeder reactor and several light water or high termperature gas cooled reactors can be called symbiotic. The combination power system is supposed to be almost entirely self-sustaining in terms of fuel. The breeder generates fuel for the fissile fuel reactors but, in turn, it is charged with only fertile fuel. Almost no additional fissile fuel is needed. Most important, the charge can be made up of the depleted uranium or thorium from the fissile fuel reactors. This obviates much of the current waste disposal problem. Additionally, the tails, or waste, resulting from the uranium enrichment process, which belongs to the customer and which is currently useless, can also be utilized by a breeder reactor. Again, a waste product, which now gives rise to either a disposal or an inventory cost, would have a positive value.

Dr. Dixie Lee Ray has pointed out that breeder economics does not depend only upon the cost of construction and operating costs of the plant. It also depends on the entire fuel cycle including the design and testing of advanced fuels.(60) The issue may be put more concisely. The breeder reactor has a higher capital cost and a lower fuel cost than a light water reactor. Therefore, for commercial operation the present discounted value of the fuel saving must be greater than the present discounted value of the extra capital expenditure. The higher the capital cost rises for the breeder, including research, development, cost overruns and inflation, the greater must be the price of natural and/or enriched uranium if the program is to be justified on commercial grounds.

Original cost estimates for the demonstration breeder were about $699 million.(61) This does not include a share of the cost of the Fast Flux Test Facility which is considered essential to the breeder program. Original estimates for the Facility were $88.7 million for construction and $105 million for research and development. The budget for fiscal year 1973 indicated a cost overrun of $83.4 million.(62) At the end of 1973 it was already scheduled to cost $400 million and be delayed until 1977.(63) By the end of 1973, the Facility was reported behind schedule and over budget. The scheduled startup date of 1980 for the breeder was regarded as shaky.(64) Both TVA and Commonwealth Edison were already asking for indemnification against cost overruns.(65) The utilities engaged in the program had tried to pledge no more than their original $250 million commitment, leaving the AEC responsible for any cost overruns. However, the Joint Committee on Atomic Energy required that a formula more equitable to the AEC be worked out.(66) In contrast, Southwestern Public Service Company has tentatively offered

General Atomic Company up to \$100 million toward the building of a privately developed gas cooled breeder reactor.[67] More important, the breeding gain, or fuel generated by the breeder reactor for use in fissile reactors, was no longer considered as great as was originally thought. Therefore, the need for the Test Facility increased in order to develop advanced fuels in an effort to get the doubling time down to no more than ten years.[68] The longer the doubling time, the smaller the quantity of fuel generated per unit of time for use in the fissile reactors and the lower the value of the breeder reactor either separately or as a part of a symbiotic process.

Currently, the breeder is expected to cost \$1.74 billion by 1982 instead of the \$700 million with a 1980 completion date forecast two years ago.[69] The Office of Management and Budget is reviewing AEC budget requests and the EPA has disputed the AEC's Draft Environmental Statement.

Given the cost and fuel gain problems, AEC support of high uranium prices is consistent with its support of the breeder reactor. However, when and if the breeder is truely commercial, the need for U_3O_8 reserves will be mitigated. This is especially true if the AEC's symbiotic scenario is correct. AEC Commissioner Kriegsman appears to believe that this will occur after the year 2000.[70] If the AEC wished to reduce dependence on high cost uranium, more fabrication plants could be built to permit the recycle of the plutonium produced in present nuclear plants. Currently, there is no plutonium recycling and the AEC has stopped buying the product. Utilities have, in the past, been in the habit of taking a credit for the plutonium generated in the normal course of their operation. This has allowed them to subtract about 0.21 mills per kilowatt hour from the anticipated cost of electric generation. Under present circumstances, it would seem more logical to consider the plutonium in terms of either a costly waste disposal prob-

lem or a fuel inventory, the holding of which involves a cost. Similarly, increasing the capacity of reprocessing plants would reduce the demand for new enriched uranium for core reloads. Currently, the reprocessing delay is measured in years, involving a significant storage and inventory cost problem.

SECTION IV FOOTNOTES

1. The Economist, April 27, 1974, p. 114.

2. Wall Street Journal, April 11, 1974.

3. Atomic Industrial Forum, Nuclear Industry, February 1974, p. 46.

4. U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 2 Sess., Part I, Phase I, July 31, and August 1, 1973, p. 100.

5. U.S. Atomic Energy Commission, "News Release," June 25, 1974.

6. Atomic Industrial Forum, Op. Cit., February 1973, pp. 52-53.

7. Ibid., February 1974, p. 37.

8. Ibid., October 1973, p. 39.

9. Ibid., October 1973, p. 37.

10. Ibid., November 1973, p. 47.

11. Ibid., April 1974, p. 35.

12. Business Week, September 14, 1974, p. 35.

13. Atomic Industrial Forum, Nuclear Industry, June 1973, p. 39, and U.S. Atomic Energy Commission, "News Release," No. 660, May 9, 1974.

14. Atomic Energy Commission, Uranium Exploration Expenditures in 1972 and Plans for 1973-74, May 1973, figure 2.

15. Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1973, p. 65.

16. Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1972, p. 5.

17. Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1973, p. 5.

18. Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1972, p. 8.

19. Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1973, pp. 27-29, 35, 40.

20. Ibid., p. 21.

21. Atomic Industrial Forum, Nuclear Industry, May 1972, p. 25.

22. Ibid., May 1972, p. 31.

23. Ibid., August 1972, p. 17.

24. Ibid., December 1973, p. 21.

25. Business Week, March 2, 1974, p. 42.

26. Wall Street Journal, August 13, 1974.

27. Ibid., September 3, 1974.

28. Atomic Industrial Forum, Nuclear Industry, December 1973, p. 21.

29. Idem.

30. Atomic Industrial Forum, Nuclear Industry, February 1974, p. 44.

31. Ibid., April 1974, p. 37.

32. Ibid., February 1972, p. 18.

33. Ibid., June 1972, pp. 36-37.

34. Ibid., November 1973, p. 21.

35. Ibid., December 1973, p. 20.

36. U.S. Congress, Joint Committee on Atomic Energy, Op. Cit., p. 86.

37. Ibid., p. 90.

38. Atomic Industrial Forum, Nuclear Industry, November 1973, p. 73.

39. Atomic Energy Commission, Statistical Data of the Uranium Industry, January 1973, p. 57.

40. Business Week, March 2, 1974, p. 42.

41. Wall Street Journal, September 3, 1974.

42. Atomic Industrial Forum, Nuclear Industry, November 1973, p. 21.

43. Ibid., January 1974, p. 26

44. M. Rieber, Low Sulfur Coal: A Revision of Reserve and Supply Estimates, Center for Advanced Computation, University of Illinois at Urbana-Champaign, CAC Document No. 88, November 1973.

45. Atomic Industrial Forum, Nuclear Industry, February 1973, p. 53.

46. Ibid., June 1972, pp. 34-36.

47. Ibid., p. 17.

48. Ibid., November 1973, p. 48.

49. Ibid., p. 22.

50. New York Times, September 6, 1974, and Wall Street Journal, September 6, 1974.

51. Business Week, September 14, 1974, p. 35.

52. The Economist, April 27, 1974, pp. 113-114.

53. Atomic Industrial Forum, Nuclear Industry, March 1972, pp. 11-18.

54. Ibid., November 1973, p. 52.

55. National Coal Association, Bituminous Coal Data, 1971 edition, p. 14.

56. Atomic Industrial Forum, Nuclear Industry, December 1973, p. 21.

57. Ibid., March 1974, pp. 5-10.

58. Ibid., August 1973, p. 39.

59. Ibid., November 1973, pp. 16-17.

60. Ibid.

61. Ibid., August 1972, p. 4.

62. Ibid., p. 15.

63. New York Times, December 19, 1973.

64. Atomic Industrial Forum, Nuclear Industry, November 1973, pp. 16-17.

65. Ibid., June 1973, p. 14.

66. Business Week, November 10, 1973, pp. 22, 24.

67. Wall Street Journal, September 19, 1974.

68. Atomic Industrial Forum, Nuclear Industry, November 1973, p. 17.

69. Wall Street Journal, September 18, 1974.

70. Atomic Industrial Forum, Nuclear Industry, February 1974, p. 12.

SECTION V: FUEL CYCLE
COMPONENT COSTS, BACKGROUND MATERIAL

Section III presented the methodology for evaluating nuclear reactor fuel cycle costs. Explicit fuel cost calculations in 1980 dollars for a model 1,000 MWe reactor were presented. In Section IV, a discussion of one component cost, natural uranium, was examined. In this Section, background material concerning other components of fuel cycle costs will be discussed. Although much of the data are qualitative, they show that the unit costs used in this study are conservative. The ordering of the discussion follows the cost component itemization in Table III-2.

A. Uranium Hexaflouride Conversion

In Table III-1 conversion costs in 1973 dollars were reported to be \$2.97/KgU (AEC) and \$2.52/KgU (NPC). In Section V it was shown that market contracts for UF_6 were \$18.60/KgU for 1972 delivery, \$20.45-20.80/KgU for 1975 delivery and \$21.00-26.15/KgU for 1976 delivery.(1) Escalating the AEC conversion costs at seven percent/annum to 1976 yields \$3.64/KgU. Subtracting this from the 1976 UF_6 bid prices gives an implied price for U_3O_8 in 1976 of \$7.89-10.23/lb. The same methodology implies a \$7.20/lb. price for U_3O_8 in 1972. Unfortunately, from the same source, it appears that U_3O_8 for 1972 delivery was \$6.10-6.50/lb. while for 1976 delivery, the range was \$7.73-8.50/lb. Starting with these U_3O_8 prices and deducting from the UF_6 price yields 1972 conversion costs of \$4.30-5.18/KgU rather than the AEC's estimates of \$2.97/KgU. Using the same methodology, implied conversion costs in 1976 are \$3.51-6.35/KgU.

The use of the AEC stockpiled uranium to reduce the separative work unit demand of utilities reduces the cost to the utilities. However, this is at the expense of commercial conversion plants. The stockpile is converted to UF_6 in government facilities despite excess conversion capacity in the private sector. The government cost is reported to be \$.30-\$.40/lb. uranium. The private cost is estimated to be over \$1.25/lb. uranium. The difference arises because the government cost basis excludes taxes, certain depreciation, and profits. According to Allied Chemical, this is a subsidy to the toll customers. To the extent that the government stockpile is used, the costs of conversion used in Section III are lower than those based on fully private usage.(2) When government stocks are exhausted, average conversion costs will rise.

The AEC apparently uses the commercial UF_6 conversion charge of \$2.90/KgU (\$1.31/lb.U) plus its estimate of the current commercial price of uranium concentrates to reach the value for the additional feed needed to operate at a higher tails assay. This becomes a component of the charge for enrichment services. The logic is that it results in the same price utilities would pay if they supplied the additional feed themselves. However, if the cost of the uranium in the stockpile plus the imputed interest is greater than the current commercial price of uranium concentrate, the profit to the government on conversion will be less than the loss on the uranium in the stockpile. As the stockpile was created for defense purposes, there is no requirement for full cost recovery.(3)

B. Uranium Enrichment

The three gaseous diffusion enrichment plants in the United States are at Oak Ridge, Tennessee; Paducah, Kentucky; and Portsmouth, Ohio. The size of these plants was based on the need to meet cold war requirements for fully enriched uranium for atomic bombs. This mission was rendered obsolete by the 1952 development of the H-bomb. Subsequently, the plants were run at minimal capacity and have still not reached full capacity levels. By 1970, the power level of the plants was about 1,900 MWe or about 31 percent of the full rated capacity. In terms of the output of enriched uranium for civilian reactors, even at the lower overall capacity level, the plants far exceeded their requirements. This is because of the significantly lower enrichment levels required for power plants compared to the level needed for weapons grade (or HTGR) uranium. Had the enrichment industry been privately owned and operated, with the end of their original mission, it is probable that one or two of the enrichment plants would have suspended operation or failed. As a government operation this was not the case.

1. Enrichment Supply-Demand

The start of the AEC interest in civilian nuclear power goes back to 1963 and a new mission. Of interest in this study is the price of enrichment services when there is a large amount of excess capacity and the price when the excess capacity disappears. Economic theory suggests that in the former case price would be just sufficient to cover incremental costs for a government plant. Moreover, a privately owned plant may incur additional costs due to taxation and royalties. The

price may include some profit. The capital costs of the enrichment plant and the past research and development expenditures committed when the plant was developed to produce weapons grade enrichment services should be regarded as sunk costs which are not recoverable under the new circumstances. The price per separative work unit would be relatively low. Whether the plants are privately or governmentally owned, as the demand for separative work units rises, the price of these units would not rise rapidly until capacity is approached unless incremental costs of operation are rising at a faster rate than output. As capacity is reached, rationing by the price system becomes necessary. It is at this point in time that new plants, either public or private, must be built and a new price structure developed. Therefore, it is important to determine when the existing enrichment plants will reach full capacity. Therefore, an evaluation of spare enrichment capacity is important with respect to the price of separative work units because it determines whether or not the price should be based upon existing enrichment facilities or on the cost of construction, public or private, of new enrichment facilities. The decision is current because it takes approximately six and one-half years to construct a diffusion plant or five and one-half years to construct a gas centrifuge plant. The power for the diffusion plant must be provided by the construction of new electric utility capacity. Assuming that these are nuclear, the time horizon is approximately nine years.

AEC estimates of U.S. enrichment capacity are presented in Table V-1. Like all estimates they are based on specific assumptions.

(1) AEC estimates of foreign and domestic nuclear power growth are based on their best estimates of reactor developments through the year 2000.

TABLE V-1

U.S. Enrichment Capacity - AEC Projection

Cumulative Separative Work

(10^6 SWU)

Through FY	(1) Committed	(2) Available	(3) (2)-(1)	(4) (3)/(2) (Percent)
1974	12.0	27.7	15.7	56.7
1975	20.4	41.9	21.5	51.3
1976	29.3	57.6	28.3	49.1
1977	38.7	75.7	37.0	48.9
1978	49.7	95.5	45.8	48.0
1979	60.4	116.1	55.7	48.0
1980	71.7	139.7	68.0	48.7
1981	83.8	165.3	81.5	49.3
1982	96.2	192.2	96.0	50.0
1983	108.5	219.4	110.9	50.5
1984	120.7	247.1	126.4	51.2
1985	132.4	278.8	142.4	51.8
1986	144.7	302.6	157.9	52.2

Source: Atomic Industrial Forum, Nuclear Industry, December 1973, p. 19.

Note: Committed includes: non-power and other domestic and foreign requirements contract, other foreigh agreements and domestic fixed commitment contracts.

These include approximately 280,000 MWe in the U.S. and 303,000 MWe of installed nuclear capacity in the rest of the world, excluding the East Bloc countries, by the end of 1985.

(2) Demand includes government and non-power applications for the military, production reactor support, the production of highly enriched material for domestic and foreign test reactors, engineering test reactors, and critical facilities.

(3) The AEC assumes a credit for the return of enriched materials for recycling from reactors.

(4) For purposes of the projection, the power characteristics of reactors are those listed in AEC document, WASH-1139.

(5) The AEC assumes recycling of plutonium on the following schedule: 25 percent of the available plutonium will be recycled as early as 1977, 50 percent will be recycled by 1978, 75 percent by 1979, and 100 percent by 1980. Shortly thereafter, due to the introduction of the breeder reactor, it is assumed that the amount of plutonium recycled will fall to zero.

(6) AEC projections are based upon the introduction of the breeder reactor by 1986 with market penetration at the rate the AEC hypothesized for the light water reactors since 1967. An

alternate forecast assumes that the breeder will not be introduced until 1990.

(7) The amount of enrichment available overseas is based on United Kingdom and French capacity and inventories with further expansion expected in a few countries, excluding the East Bloc, at some time after the early 1980's. Specifically, it is assumed that the U.S. will supply 75 percent of the needs of the rest of the world, excluding the East Bloc, through 1985, and 60 percent from 1986 through the year 2000.

(8) The tails assay at the enrichment plants for the fiscal years 1974-78 will be 0.30 percent, for FY 1979-81 it will be 0.275 percent, and for FY 1982 through FY 2000, it will be 0.30 percent.

(9) AEC production plans are based on increasing the power level at the diffusion plants to the full power level of 61,000 megawatts by FY 1979, the introduction of the Cascade Improvement Process with first appreciable production by FY 1976, and the introduction of the Cascade Uprating Program with first appreciable output starting in FY 1979.(4)

It is beyond the scope of this paper to make an exact assessment of the AEC projections. However, it is possible to make some qualitative judgments.

(1) The AEC estimate for 1980 has twice been scaled down from the estimate in WASH-1139 which was 132,000 MWe. If for 1985, the projected maximum reactor capacity developed in this study is taken as the base, the number of separative work units demanded is reduced by about ten percent. Realistically, the reduction should be even greater.

(2) The assumption of a credit for the recycling of the spent material from the reactors does not appear to take into account the current long term lag between discharge and recycling. It also fails to consider the present condition of the processors. Currently, the time lag is of the order of four years. Until this is altered, rather than recycled uranium, there will be greater than anticipated requirements for fresh feed and the number of separative work units must also be greater than those anticipated.

(3) Compared to the model plant discussed in this study, the power characteristics assumed in WASH-1139 indicate a lower burnup rate, approximately the same efficiency, and a load factor of 80 percent. Decreasing the load factor to 65 percent decreases the amount of uranium and, therefore, the enrichment services necessary. A low burnup rate also decreases the amount of uranium and enrichment necessary.

(4) The amount of plutonium to be recycled appears to be overly optimistic, at least within the time dimension suggested. Currently, there is virtually no plutonium recycled and it does not appear that capacity will be available as early as 1977. As a result, more fresh feed and, therefore, more separative work units will be required. The AEC estimates that if there is no plutonium recycling, the requirement for separative work units increases by about 25 percent.

(5) Given the notorious delays in the breeder reactor program, it would appear that even a 1990 date for the operation of the first commercial breeder reactor is optimistic. There will almost certainly not be a market penetration at the rate of the light water reactors. If the breeder reactor is delayed from 1986 to 1990, the increase in separative work units increases by about eleven percent.

(6) The amount of U.S. enrichment services demanded for European reactors depends upon the final outcome of the Eurodif-URENCO dispute concerning enrichment capacity and the availability of Russian enrichment services. This is discussed below. Here it may be noted that if there is a future shortfall of U.S. uranium enrichment capacity, it could be well within the national interest to exclude foreign purchasers. Elimination of the foreign commitment is of the same

order of magnitude as a shift in the recycling of plutonium to zero from 100 percent.

(7) If the tails assay is lower than that specified, separative work unit requirements increase by about six percent.[5]

Given the slowdown in the rate of increase of electric power consumption, it is difficult to determine when additional enrichment capacity would be needed. In 1973, it was reported that approximately 25 million separative work units would be needed in order to avoid an enrichment gap. It was assumed that the present capacity would be contracted to the full by the end of 1974. After that, the AEC could not let any further contracts for enrichment. Consequently, General Electric, Westinghouse, and others would no longer be able to sell reactors because the sale, to be effective, would have to have a concomitant fuel contract. It was reported that four new plants would be needed between the end of 1982 and the end of 1985 if utilities were to build reactors at the expected rates.[6] At the end of the year, it was assumed that enrichment facilities would have to be constructed at the rate of nine million separative work units every 18 months during the 1980's.[7] In hearings before the Joint Committee on Atomic Energy, it was argued that, in order to keep the light water reactor program going at the rate expected by the AEC, three new diffusion plants would have to be built by the end of 1985. A supply shortage in existing plants was predicted by 1982.[8] Phase II of the JCAE hearings continued the expectations of enrichment shortages. It was reported that the demand for nuclear fuel was expected to exceed AEC supplies, including the uprated and improved gaseous diffusion plants, by the early 1980's.[9]

By mid-1974 it was apparent that some changes in AEC predictions had taken place. It was reported that, with the delay in building new nuclear plants, it was thought that the AEC would be able to provide fuel processing, possibly until the mid-1980's with existing plants.(10) The AEC had already planned to enrich foreign uranium for domestic customers up to a maximum of ten percent of the uranium furnished for enrichment by the customer. This was to start in 1977. (Originally, the Commission had planned to remove uranium enrichment restrictions on foreign uranium by 1973. However, the market for uranium was weak and the AEC sought to protect the market for domestic companies.) The percentage of enrichment of the foreign uranium would increase to 15 percent in 1978, 20 percent in 1979, 30 percent in 1980, 40 percent in 1981, 60 percent in 1982, and 80 percent in 1983. No restrictions would be imposed following 1984.(11) If the market for enrichment services becomes tight, this schedule might be easily revised. It was also reported that the AEC had found the needed extra capacity for the 15 U.S. and 33 foreign utilities which had been affected by its last enrichment contract cut-off. Moreover, forty-five additional plants could be served if plutonium could be used as a fuel supplement. This increase in contracting capacity will serve all U.S. plants due to be on-line before June 30, 1982. The AEC reports that it will use its small enrichment capacity reserves and will draw down its enriched stocks. The recycled plutonium is expected to cover one-fifth of the total fuel demand.(12) However, as yet there is no plutonium recycling.

Part of the current supply-demand problem exists because the AEC requires long term contracts for fuel enrichment. These are designed to firm up separative work unit demand and aid the mining industry.(13) To help maintain the contracts, termination charges are high. If the fuel contract is terminated

prior to the end of the contract, these charges range from 57.3 percent of the charge per KgU for the remainder of the enrichment period, if the contract is terminated within the first year, to 23.9 percent if the contract is terminated in the ninth or tenth year. The total on which the percentage is imposed includes escalation of costs and gross additions. For example, increases due to added electric costs for separative work.(14)

To avoid the rigors of the AEC contracts, four programs are being developed which are akin to the creation of a spot or exchange market for nuclear fuel. These are the World Nuclear Fuel Market, backed by the Nuclear Assurance Corporation, the Separative Work Administration Pool, the Separative Work Units Corporation, and the pool backed by the NUS Corporation.(15)

2. Separative Work Unit Costs

In estimating the future price of enrichment, whether public or private, there are a number of uncertainties. A sample list would include AEC licensing requirements, the price of uranium, whether or not plutonium is recycled, the date of the advent of the breeder reactor, and the cost of electricity, of primary interest for gaseous diffusion plants and of one-tenth the interest for gas centrifuge plants. Additional uncertainties arise in the area of financing: bond prices and the ability to sell stock, equity/debt ratios, the cost of research and development, and whether the results are passed directly from the federal government to private licensees or whether they must be paid for, allowable profits, tax rates, insurance, and the type and degree of competition among firms, not only the gaseous diffusion plants but also the number of potential suppliers for the components of the enrichment plants. The ammortization or payout period is also important because,

while the original plants were ammortized over a period of 33 years, if the breeder reactor were to become of major importance by the year 2000, a diffusion plant coming on-line in 1985 would have 15 to 20 years of useful life. If the breeder is unimportant until 2020 or 2030, an enrichment plant can be ammortized over 30 or more years. Finally, there are costs associated with the feed and product flywheels, insurance, safeguards, and new environmental requirements.

a. Capital Costs

Using AEC cost estimates for a gaseous diffusion plant with a capacity of 8.75 million separative work units per year, at a new site, and escalating at an annual rate of seven percent from FY 1974 to FY 1980, capital costs for the plant, including CIP technology, are $2.1 billion. For a gaseous diffusion plant using advanced technology, the 1980 cost is $1.8 billion. These costs exclude in-plant uranium feed and enriched product inventories and pre-production. Furthermore, the estimates are for a government rather than a private plant. Therefore, the costs exclude taxes, royalties, research and development and the cost differential of money in the private sector. Finally, the costs include the enrichment plant alone. They do not include the necessary power plants required to serve a gaseous diffusion plant. The AEC estimates that it requires 3.3 kilowatts per separative work unit capacity at these gaseous diffusion plants.(16)

One of the capital problems involved in the private development of enrichment facilities is that assuming that plutonium recycle and/or the breeder reactor become generally available, the facilities may not be needed after 2020 or 2030. Therefore, companies building enrichment plants in the 1980's and 1990's must recover costs in a short period of time. Moreover, the utilities, as consumers, do not wish to become

involved in the enrichment process. Commonwealth Edison has urged that the electric power industry not be required, directly or indirectly, to supply any of the enrichment capital needed. The utilities appear to be quite willing to subscribe to five or ten year enrichment contracts, but they do not want to have to undertake long term take-or-pay contracts.(17)

Originally, there had been hope that one, or both, of two private corporations, the Uranium Enrichment Associates (UEA), or the Exxon Nuclear-General Electric team would be interested in building an enrichment facility. Alternatively, the government, as proposed by Congressman Craig Hosmer, would construct an interim facility to be run by the U.S. Enrichment Corporation. The UEA had promised a go/no-go decision by July, 1975, although if they decided upon a gas centrifuge, the decision would be delayed. The GE-Exxon decision was less firm and was to be made sometime in 1976. While both the Office of Management and Budget and the AEC favored private development of enrichment facilities, neither of the private groups could promise to be able to sell enrichment contracts on a specific date.(18) In July, 1974, it was expected that the UEA would make a final decision on whether to build a gaseous diffusion plant by October or November. According to the UEA, the major problem was financing. UEA expected the utilities to commit themselves to 20 year contracts for nuclear fuel supplies with payment in advance. It was felt that government subsidies would be unlikely but that the plant could be operational by mid-1983. The plant would be capable of supplying enrichment services for about 90 nuclear power plants of approximately 1,100 MWe capacity each.(19) However, by September 1974, of the original three members of the UEA, Bechtel, Union Carbide, and Westinghouse, only the Bechtel Corporation remained.(20) In the same month, GE backed out of its partnership with the Exxon Corporation.(21) More recently, Atlantic-Richfield and Electro-

Nucleonics are jointly deciding on whether to make a bid to build a gas centrifuge plant. If constructed, the plant would be on-line by 1979-1980 and would serve three to four reactors. Electro-Nucleonics, in conjunction with Burns and Roe, is also studying the construction of a gas centrifuge plant for TVA.[22]

The basis for these decisions appears to be two-fold. First, on the part of the utilities, Commonwealth Edison and its associates issued a statement concerning the problems of dealing with a private enrichment monopoly.[23] Furthermore, the Edison Electric Institute, as spokesman for the privately owned electric utilities, and supported by TVA, in a position which had changed 180 degrees from its earlier one, told the JCAE that the government should assume the task of expanding the nation's capacity to enrich uranium. Support and endorsement of the new position by the American Public Power Association was expected. Edison Electric and TVA witnesses told the Joint Committee on Atomic Energy that the UEA was offering unbusinesslike terms, in effect asking the utilities to assume all the risks of expansion. TVA's power manager testified that the UEA proposals, "...do not yet indicate a clear willingness to accept the risks associated with entering a new large scale capital intensive enterprise on a normal competitive basis." He noted that the enrichment group wanted the utilities to sign up for enriched uranium under contracts that would oblige the utilities to make payments even if the fuel was not available on schedule. The administration argued, on the other hand, that if the utilities wished to assure their future supplies of fuel, they would have to come to terms with UEA, the one industry group that proposed going into the business.[24]

From the point of view of the companies potentially entering the enrichment business, they must obtain the results of research, development, and expertise from the government for either the gaseous diffusion or the gas centrifuge enrichment

operation. Problems exist concerning classified information and costs. The companies appear to want subsidization either directly, or through AEC purchase of the output of enriched uranium at negotiated (i.e., non-market) prices.

b. SWU Price Estimates

Enrichment service charges were originally established in 1967. Toll enrichment started on January 1, 1969. Prior to 1968, enrichment cost $30/SWU. In the period from 1968 through February 1971, the price was $26/SWU; from February 1971 to September 1971, it was $28.70/SWU. In September 1971, prices rose to $32/SWU; and in August 1973, they rose again to $36/SWU for long term contracts and $38.50/SWU for short term contracts. After January 1974, long term contracts were based on a $36 price with a two percent per year escalation.(25) The SWU charges exclude interest on the cost of natural uranium associated with pre-production. Only the market value of the feed is covered. If interest charges are included, it is estimated that the price would increase by about $2.50/SWU.(26)

At the AEC rate of increase the prices quoted above imply separative work unit charges of $40.54 per unit in 1980 and $44.76 in 1985. Using an inflation rate as low as seven percent, implies separative work unit charges of $54.03 in 1980 and $75.77 by 1985.

In line with current inflation rates and general increases in the electricity rate, a seven percent rate of inflation seems much more reasonable than that used by the AEC. If the AEC were to maintain its rate in the face of mounting inflation this could be considered a subsidy to the utilities. In a review of separative work unit charges, the AIF noted that, in setting the new rate, the AEC would have gone further than the two percent per annum increase because of increasing electric costs. However, the idea was rejected.(27) The reason

may, perhaps, be traced to the trade-off between a desire for a low separative work unit price for the benefit of the utilities and the domestic reactor program, and a higher price in order to maximize the balance of payments advantage accruing to U.S. enrichment.[28] At least in the past, given the rate of European reactor developments, the former would appear to be of greater benefit to the AEC.

Government and private industry differ somewhat in their estimates of future separative work unit charges. Government estimates for a government owned new gaseous diffusion plant range from $51.08 to $60.82/SWU in 1974 dollars. The government estimate of charges at a privately owned plant is $64.91/SWU. The price estimate for a gas centrifuge plant is lower, but with a relatively wider range. In 1974 dollars, a government owned gas centrifuge plant is expected to charge between $29.87 and $47.83/SWU. A similar private plant would charge in the range of $40.06 to $59.53/SWU.[29] If the government's gaseous diffusion plant estimates for separative work unit charges are escalated at seven percent to 1980, the range for the publicly owned plant is $76.66 to $91.27/SWU. A newly built private plant would charge $97.41/SWU. The 1980 enrichment charges used in this study (Table III-2) were $97.

In making the estimates, the government used several assumptions.

(1) The plants were ammortized over a period of 15 years. This is realistic only if it is assumed that the breeder reactor will be on-line according to early AEC schedules.

(2) It is assumed that the capital cost will be $1.5 billion. This is lower than the AEC capital requirements cited above.

(3) The cost of power, which is critical particularly for the gaseous diffusion plant, is estimated at 10 mills per kilowatt hour. Given the recent rate of increase of electric rates, 10 mills/Kwh is a low price estimate for 1980.

Aside from the general assumptions, which affect both public and private facilities equally,

(1) Government facilities were assumed to be funded on the basis of 100 percent debt, but at an interest rate of only 5.5 percent.

(2) Private plants were expected to have a debt/equity ratio of 50/50. This implies a low debt ratio compared to the standard utility debt/equity structure. This is important because the cost of debt assumed for private plants was only eight percent; far lower than current rates.

(3) The estimates for the gas centrifuge plant are much more tentative than those for the gaseous diffusion plant. The former is in a far earlier stage of development.

Private estimates of separative work unit charges also vary widely. Commonwealth Edison, based on escalation of data provided by the Atomic Industrial Forum, estimates 1980 separative work unit charges at $70 to $80/SWU.(30) Former AEC Commissioner, Phillip Sporn, reporting for the Electric Utility Consortium Plan, estimated 1982 charges at $47.28/SWU. His estimates are a classic example of "accentuating the positive."

(1) Plant costs for 1982 are $1.5 billion; exactly the same as the government's estimate for 1974. Assuming an inflation rate of seven percent and a plant construction start-up date of 1977, his estimates imply plant costs of $1.84 billion.

(2) Power costs are estimated at only 8 mills/Kwh. If power costs are 10 mills as suggested by the government, the increase in the Sporn estimates for the first two items alone is $7.16/SWU, bringing the separative work unit costs up to $54.44.

(3) The ammortization period is 20 years rather than 15 years.

(4) The debt/equity ratio is 90/10; somewhat higher than utilities have currently been able to establish, and the cost of the debt is only eight percent; far less than they have been able to obtain.

Aside from the cost of construction, the critical operating elements in the separative work unit charge are the percent enrichment, the tails assay and the electric power requirement. For example, in order to produce one kilogram of uranium of three percent enrichment, if the tails assay by weight percent of U^{235} is 0.10 percent, and the feed component is 4.746 kilograms of uranium per kilogram of product, the separative work requirement is 5.981 SWU/Kg of uranium product. If the tails assay is 0.50 percent, then the feed component must be 11.848 KgU/KgU product. However, the number of separative work units required falls to 2.429.[31] Obviously, it is

possible to hold any one of the four components, the level of enrichment, the tails assay, the feed component, or the number of separative work units, constant and, within limits, vary the other three.

The electric power component depends on two factors. One is the cost of electricity in mills per kilowatt hour, the other is the number of separative work units actually used. The latter depends on the considerations discussed above. In general, it requires 8,250 Kwh electrical input to produce one kilogram of 2.8 percent enriched uranium. In a boiling water reactor this would yield approximately 217,800 Kwh of electrical output. The ratio is 3.8 percent, but this depends on the reactor load factor, burn-up rate, and the efficiency of the plant.

In early 1973, the Atomic Industrial Forum reviewed the components of separative work charges. They estimated the electric power component to be $35.70/SWU in 1983, from $21.68 on January 1, 1973. Adding the power component, the labor component, and a constant component together they arrived at a ceiling charge (price) of $39.12/SWU for January 1, 1973, and $58.21/SWU for 1983. However, the electric power component costs were escalated prior to the new higher fuel prices. Furthermore, while electric rates increased according to AIF, by 1.97 percent per annum from January 1, 1967 to January 1, 1970, they rose by 11.8 percent per annum between January 1, 1970 and January 1, 1973. However, the AIF assumed that between July 1, 1972 and 1983, electric power costs would escalate at an average rate of only 5.14 percent per annum. If the power component is escalated at the 11.8 percent rate existing between 1970 and 1973, by 1983 the power component alone is $66.14/SWU yielding a separative work unit ceiling price of $88.65. If the escalation is assumed to be 8.47 percent, halfway between 11.8 and the 5.14 percent assumed by AIF, the power

component cost alone is \$48.88/SWU yielding a ceiling charge for separative work units of \$71.39 by 1983.

It is possible to similarly increase the labor component because its annual percentage increase was 5.63 percent between January 1967 and January 1970, and 7.0 percent per annum between January 1970 and January 1973. AIF, in its escalation, assumes an average increase in the labor component of only 5.84 percent per annum between July 1, 1972, and 1983. This is surely too low.[32]

3. European Enrichment

The amount of spare domestic enrichment capacity is partially dependent on the demand for enrichment in Europe. Annual consumption of enriched uranium in western Europe is currently about 2,500 metric tons. It is expected to be just under 9,000 tons by 1980, and just over 21,000 tons by 1985. The French group, Eurodif, plans to build a gaseous diffusion plant which can produce about 10,000 tons of enriched fuel. It is expected to be on-line by 1980. The plant, if running economically at full capacity by the beginning of the 1980's, would leave little room for imports from the United States. A rival group, URENCO, which is sponsoring a gas centrifuge enrichment facility, fears that there will be excess capacity. Even though American terms are not as favorable as they used to be, the Soviet Union has become a potentially large supplier in the western European market. The planned URENCO centrifuges would yield only 2,000 tons of enriched uranium per year by 1980, but capacity would be increased to 10,000 tons by 1985. However, since none of the new European power stations that will use the enriched uranium have yet been built, and may be delayed because of pressure from conservationists, the demand estimates for the 1980's may be shifted to the 1990's.[33] Currently, the URENCO consortium expects to have two semi-

commercial centrifuges operational by 1975. The output of the two is expected to go to 200,000 separative work units per year. By 1985, at a minimum, these are expected to be able to produce two million separative work units per year.[34]

Both Eurodif and URENCO feel that there is room in western Europe for only one of them. France, while it has said it will proceed alone with the Eurodif proposal, wants some assurance about finding European buyers for the fuel in the 1980's as well as an EEC understanding to stockpile enriched uranium surpluses when necessary.[35] However, it has become obvious that European utilities, like their American counterparts, are unwilling to place long term orders. Furthermore, the European utilities have asked the U.S. Atomic Energy Commission to reconsider a plan for American cooperation in building European enrichment capacity. The original suggestion for cooperation dated from 1971, but was linked by the AEC to Draconian conditions which have not basically changed. Furthermore the AEC no longer believes that the suggestion for cooperation is realistic. However, the AEC has announced that it is ready to consider postponing contract deadlines for European utilities already engaged in serious contract negotiations and is confident that the U.S. will find buyers for its enriched uranium.[36] The willingness of the U.S. Atomic Energy Commission to be more flexible about tying European utilities to long term contracts (previously these had been for eight years) was based on the desire of the AEC to assure itself of customers before it committed government money to any new enrichment plant construction in the United States. Despite this, and despite the opinion of France's original minority partners in the project, Spain, Italy, Sweden and Belgium, who believed the French must win agreement from European utilities to buy at least two-thirds of the annual production, the French government announced that it formally guaranteed to begin construc-

tion of a gaseous diffusion plant in January, 1974. By then, some of the utilities that refused to back the French plan had already committed themselves to buy fuel from URENCO or from the United States Atomic Energy Commission. The French offered to scale down their plans so that the full capacity level would be reached by 1985, four years after the originally scheduled date. However, at a low volume, the scaled down project, which would cost between $1.6 and $1.7 billion, was expected to produce heavy losses.(37)

By the first quarter of 1974, the Eurodif-URENCO dispute was still unsettled. Sweden had pulled out of Eurodif and many European electric utilities were signing up with the United States, leaving the expectation that Eurodif capacity would be surplus by the late 1970's. Japan, however, placed an order for enriched uranium with Eurodif and suggested that it take a share in the project; perhaps the share recently abandoned by Sweden.(38) Additionally, Japan and Australia, with either France or West Germany, plan a uranium processing plant to be located in Australia. Japan will provide the money and the market, Australia the land and the uranium, and West Germany or France the technology.(39)

Unless the rate of increase in the demand for nuclear power becomes higher than the current rate, a possible result of Arab success in pricing oil out of the long term market, if current enrichment plans are put into effect, it is likely that an international surplus of enrichment capacity will develop in the mid-1980's. However, if additional U.S. capacity becomes available, history suggests that governmentally supported restrictive practices will prevent the SWU price from falling.

C. REPROCESSING COSTS

In December 1972, the Atomic Industrial Forum reported a ballpark estimate of fuel reprocessing costs, excluding the cost of high level waste disposal, of $40,000 per metric ton. In 1962, the AEC had proposed a price of $16,850 for reprocessing.[40] Escalating the 1962 figure at seven percent, which is too high, yields a price of only $33,146/metric ton in 1972. Therefore, there was a quantum increase in prices to reach $40,000. Escalating the 1972 figure by seven percent, which is probably to low, yields a 1980 estimate of $64,231/ metric ton.

Both plutonium and uranium are recycled in the same plants. The only reprocessing firms are Nuclear Fuels Services, Inc., West Valley, New York, which expects to have a capacity of 750 tons per year when it opens sometime in 1978, General Electric, Morris, Illinois, which currently has a 300 ton per year plant, and Allied Gulf Nuclear Services, Barnwell, South Carolina, which is due to open a 1,500 ton per year plant in 1975. Atlantic Richfield entered the market briefly but dropped out. It entered by buying existing contracts for reprocessing. As a result of this, the price fell. Reprocessors have reported that they are still trying to establish what they call realistic cost/price ratios.[41]

Even though competition is very limited in this market, reprocessors have, in the past, had some serious problems. The major problem was that as long as the price of yellowcake was low, utilities were unwilling to place forward orders for reprocessing spent fuel; uranium from natural feed was available when needed. As the price of uranium rises, reprocessing becomes a more realistic activity for the utilities. Secondly, reprocessors have not given very much economic incentive to the utilities.

The future of recycling is somewhat sketchy, primarily because the conditions under which recycling is to be permitted are not yet fully defined. Therefore, utilities cannot yet initiate license modifications to permit fuel recycling in their reactors, place firm recycle orders or get firm recycle contracts, including prices. The major problem appears to be the form which the recycled manufactured product would take. This may be changed by AEC fuel restrictions.

Given AEC type projections for nuclear reactor capacity (280,000 MW in 1985) a need is estimated for one 1,500 metric ton reprocessing plant on-line every 15 months between 1982 and 1990. If only the original three plants including the Morris plant are in existence by 1985, the reprocessing backlog would be approximately 8,000 metric tons. This includes approximately 64 tons of plutonium. The total is equivalent to about 10,000 tons of natural uranium feed which must be mined and enriched. Plutonium storage by 1980 is expected to be over 50 tons.(42)

Based on AEC projections of nuclear power demand for enriched fuel, it is expected that a fourth plant will be necessary by about 1981. The plants are expected to recycle large amounts of uranium-235 and plutonium from the spent fuel, reducing the demand for mining, milling and enriching uranium. According to Congressman Craig Hosmer, the Nuclear Fuel Services and Allied Gulf Nuclear Services plants may be delayed while a third might be dismissed as nebulous.

Following the failure of the GE reprocessing plant at Morris, Illinois, the U.S. for at least two full years, will be without a facility to reprocess nuclear fuels after they are withdrawn from the cores of utility reactors. The AEC has begun a nationwide check for additional storage capacity for the unanticipated accumulation of fuel waiting to be reprocessed.(43) The Morris plant may have to be scrapped as the advanced tech-

nology apparently does not work. It was due to start in 1970 and may not start until 1978, if ever. It is estimated that the redesign and rebuilding may cost between $90 and $130 million. The other two plants cannot begin to cover reprocessing needs. The plant dismissed by Congressman Hosmer as nebulous is the Exxon Nuclear Company plant to be located in Loudon County, Tennessee, which may be operational sometime between 1980 and 1982. Thus, a reprocessing crunch is expected by the late 1970's. Utilities, therefore, are carrying a very large inventory of spent fuel and may wait years before reprocessing. Nuclear Fuels Services is currently holding unreprocessed fuels for four years and may hold it for another five years before it is returned to the utilities that own it.[44]

Due to the shortage of reprocessing capacity and the failure of the GE Morris, Illinois facility, storage of spent material to be reprocessed will have to be found for over 3,000 tons of the spent fuel between 1974 and 1978. This involves both an investment cost or alternatively a waste disposal cost.

As the reprocessing of spent fuel is expected to be cheaper than that of the enrichment of fuel from fresh feed, one can assign either a high cost of reprocessing or additional costs to enrichment.

D. PLUTONIUM RECYCLING

Currently there is no plutonium recycling. However, the AEC has recommended general approval. It expects to start recycling plutonium by 1977 with all plutonium recycled by 1980. They predict that plutonium recycling will cover about five percent of the enrichment needs of utilities by 1985 if the schedule is met. However, with the lag in fuel reprocessing capacity the likelihood is small.

If used as a fuel plutonium could reduce the annual uranium requirements in the early 1980's by about 15 percent. Alternatively, if there is no recycling, incremental enrichment capacity requirements would increase by over five percent by 1985. Furthermore, the need for the new enrichment capacity will be brought forward in time. Based on AEC estimates of the number of reactors, which should be derated, by 1975 plutonium production from all reactors will be about 5,700 kilograms per year. By 1980 this will rise to over 20,000 kilograms per year. However, even if all three fuel fabrication plants for recycling are in existence they will only be able to handle at most 3,000 kilograms per year. There is a need, therefore, for a great increase in capacity. However, this would require about a six year lead time. By 1980 the AEC expects to have plutonium recycling capacity of only 10,000 kilograms per year. As a result storage is needed, but the current storage capacity is only 4,000 kilograms while the projected demand for storage for plutonium by 1980 is about 51,000 kilograms.[45]

It would appear that rather than consider plutonium produced in commercial reactors as a credit, to be deducted from the fuel cycle costs, the production of plutonium from U^{238} involves either an inventory cost or a disposal cost. As the AEC has not yet indicated what conditions must be met for permission to recycle plutonium, there is as yet no way to make firm price commitments for recycling. Even by 1980, it is not expected that there will be much recyling so that storage must be found for over 50 tons of plutonium.[46]

E. TRANSPORTATION

The American Association of Railroads has recommended that special trains be used for the transportation of fuel, spent fuel, and waste. Among other things these trains should be limited to a speed of 35 miles per hour. It is estimated that the use of special trains would cost an additional $14/ton/mile/cask containing fuel assemblies. The use of special trains may lead to problems with respect to turn-around time, special scheduling, and special equipment.

To date there are no transportation problems. In the South and the West, regular railroad tariffs are used, but the railroads require a release from liability from either the Price-Anderson Act shipper or consignee. In the Northeast the railroads have special tariffs in addition to the released liability. Some refuse to handle wastes at all, and most indicate that they want special trains. The increased rail rates may move shippers to truck transport, but this would require very much smaller casks, many more trucks, and possibly severe road hazards. In the special case of the movement of plutonium, the proposed AEC rule is that it be shipped as a solid to avoid leakage if the plutonium is in excess of 20 curies per package. Currently, plutonium moves as an aqueous nitrate. For the utilities and processors, this is cheaper than solidifying.[47]

The bottleneck in shipping fuel is related to the number of casks available to carry the fuel assemblies. Moreover, there are only two companies involved in this activity: Nuclear Fuels Services and General Electric. This does not lead to price competition. The older form of the NFS casks, designated NFS-4, carried two boiling water reactor assemblies or one pressurized water reactor assembly. Pressurized water reactors average 120 to 200 assemblies per core loading while the large boiling water reactors average 360 to 760 assemblies

per core loading. In February 1973, there were only two NFS-4 casks available. The NFS-5 cask carries three boiling water assemblies or two pressurized water reactor assemblies. In February 1973, two were available and two more were on order. The GE casks, designated F-300, of which there was one in October 1973, carry seven pressurized water reactor assemblies or eighteen boiling water reactor assemblies. They replaced the earlier casks designated F-100 and F-200, of which there was one each with a capacity of only one boiling water reactor assembly or one pressurized water reactor assembly.

F. WASTE MANAGEMENT

1. Plutonium Contaminated Wastes

Contaminated wastes from reprocessing and fabrication plants, for example, clothing, ion exchange resins, filters, fuel hulls and solidified liquid wastes are currently buried in commercial land burial sites. So far this has been accomplished by dispersing a small quantity of waste in a large volume of land fill material. By the early 1980's the cumulative total could be in excess of eight million cubic feet, the equivalent of several hundred kilograms of plutonium. Therefore, the AEC is considering a respository. This solution is not considered attractive by the fuel industry as it would involve compaction, leaching and incineration. These increase costs and introduce more safety problems.

2. High Level Waste

High level nuclear waste material comes from both the reprocessors and the reactors. It has been estimated that solidification, transportation and perpetual care of the waste material from reprocessors would cost between \$10,000 and \$15,000 per metric ton of fuel processed. This is equivalent

of about $200,000 to $300,000/1,000 MW reactor/year added onto the fuel costs. Because the AEC has not yet firmed the solidifying activities, reprocessors are unwilling to move ahead with the completion of plans.

Reactor wastes are of the order of 9,300 cubic feet of unsolidified wastes per one thousand megawatt reactor per year. These wastes must be disposed of for the next 25 years. Currently, there are only six commercial sites in the United States. Five are owned by Nuclear Fuels Services, one is owned by Chem-Nuclear Services, Inc. While some of the wastes have a relatively short half life, cesium-137 has a half life of 30 years and plutonium-239 has a half life of 1,000 years.[48]

The Atomic Energy Commission is considering building a $100 million above ground vaulted storage for high level wastes. This would need close monitoring and is expected to be used only to the end of the century. The AEC hopes to develop a permanent method although no such method now exists. They have not yet decided upon which of three types of vaults are to be used. There are three possible sites: (1) the Nevada test site, (2) the National Reactor Testing Station, and (3) the Hanford facility. As these are all government property, no environmental review would be necessary. According to Dr. Pittman, head of the AEC Division of Waste Management and Transportation, "There is not an implicit faith that a permanent storage method will be found." The AEC considers that it does have sufficient knowledge to develop permanent salt bedded waste disposal.[49] If, however, high level wastes are not salt bedded, other means for the long term are considered either impractical or too expensive unless the highest level radioactive waste material is removed.

G. SAFEGUARDING

It takes approximately 34 pounds of highly enriched uranium or 16 pounds of plutonium to make a crude bomb. The Ford Foundation Energy Policy Project has recommended a government security force to prevent the theft of nuclear materials. Of particular relevance is plutonium and the highly enriched uranium used as fuel in the high temperature gas cooled reactors. The three percent enriched U^{235} used in boiling water and pressurized water reactors is not bomb material.[50] The most vulnerable sectors are reported to be in the area of the fuel cycle: reprocessing plants, fuel fabrication plants and transportation. The costs involved here may be passed through to the utilities.[51]

The AEC has increased the safeguarding requirements of its licensees, thereby adding to their costs, and has recognized that future requirements may have to be strengthened again.[52] Moreover, the AEC is requiring utilities to hire armed guards for their facilities. The utilities, however, contend that this should be a federal function primarily because of the additional costs.[53]

To pay for its safeguarding function, the AEC requested $87 million to hire guards, install alarm and detection systems, install fences, provide tamper-proof shipping cases, and purchase nuclear tracking equipment. The Office of Management and Budget recommended $18 million. Of the difference, $5 million was restored by the Joint Committee on Atomic Energy.[54]

SECTION V FOOTNOTES

1. Atomic Industrial Forum, Nuclear Industry, May 1972, p. 31.

2. U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong., 1 Sess., Part II, Phase II, October 2-4, 1973, pp. 317-319. (Hereafter referred to as Hearings, Phase II.)

3. Ibid., pp. 315-316.

4. U.S. Atomic Energy Commission, Oak Ridge Operations Office, New Enrichment Plant Scheduling, November 1973, pp. 2, 3 and Appendix A.

5. Ibid., p. 2.

6. Atomic Industrial Forum, Op. Cit., March 1973, p. 6.

7. Ibid., November 1973, p. 20.

8. U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong., 1 Sess., Part I, Phase I, July 31 and August 1, 1973

9. Hearings, Phase II, pp. 1, 209.

10. Wall Street Journal, July 2, 1974.

11. New York Times, December 14, 1973, and Wall Street Journal, August 15, 1974.

12. Wall Street Journal, August 7, 1974.

13. Hearings, Phase I, pp. 124, 129.

14. Atomic Industrial Forum, Op. Cit., February 1974, p. 38.

15. Ibid., p. 18.

16. Hearings, Phase II, pp. 363, 368.

17. Ibid., pp. 203-204, 210.

18. Atomic Industrial Forum, Op. Cit., October 1973, pp. 3, 5, 6.

19. Wall Street Journal, July 2, 1974.

20. Ibid., September 27, 1974.

21. Ibid., September 23, 1974.

22. Ibid., October 30, 1974.

23. Hearings, Phase II, pp. 211-212.

24. New York Times, July 17, 1974.

25. Hearings, Phase I, p. 28, and Atomic Industrial Forum, Op. Cit., February 1973, pp. 24-25.

26. Hearings, Phase I, p. 20.

27. Atomic Industrial Forum, Op. Cit., December 1973, pp. 18-19.

28. Hearings, Phase I, p. 4.

29. Ibid., pp. 146-147.

30. Hearings, Phase II, p. 304.

31. Hearings, Phase I, p. 39.

32. Atomic Industrial Forum, Op. Cit., April 1973, p. 9.

33. The Economist, October 27, 1973, pp. 75-76.

34. Atomic Industrial Forum, Op. Cit., October 1973, p. 8.

35. The Economist, December 1, 1973, p. 67.

36. Ibid., December 8, 1973, p. 63.

37. Business Week, December 1, 1973, p. 37.

38. The Economist, February 23, 1974, p. 76.

39. New York Times, November 3, 1974.

40. Atomic Industrial Forum, Op. Cit., December 1972, p. 31.

41. Ibid., December 1973, p. 30.

42. Ibid., April 1974, pp. 29-32.

43. New York Times, July 24, 1974.

44. Wall Street Journal, August 28, 1974.

45. Atomic Industrial Forum, Op. Cit., April 1974, pp. 29-32.

46. Idem.

47. Ibid., April 1974, pp. 29-32.

48. Idem.

49. New York Times, September 15, 1974.

50. Ibid., April 26, 1974.

51. Ibid., April 6, 1974.

52. Ibid., April 26, 1974.

53. Ibid., May 1, 1974.

54. Ibid., October 5, 1974.

SECTION VI: CAPITAL
AND RELATED COSTS

The data in this section, while numerical, can at best be considered qualitative. Neither secondary sources nor corporate submissions to the Atomic Energy Commission provide sufficiently disaggregated and/or mutually consistent data for comparison or analysis.

A. Capital Costs

Reported capital cost data are sparse and relatively unsatisfactory mainly because they are not sufficiently disaggregated. Even estimates for roughly similar plants due to be on-line at the same time differ widely from plant to plant because of the uniqueness of each plant and, furthermore, because of differences in contingency reserves, the interest rate used for the cost of capital during construction, escalation, and discounting. Finally, cost estimates depend on differences in cooling systems, which may not even be included in the capital cost estimates, the treatment and estimate of other direct and indirect costs, and because of differences in land values in different parts of the country.

The Atomic Industrial Forum has indicated that capital costs were \$130/Kw in May 1967, \$220/Kw in June 1969, and \$300/Kw in January 1971.(1) Presumably these costs will not continue to escalate at the increasing rate implied by this history. Using the first pair implies capital costs of about \$562/Kw in 1980, using the second two implies a 1980 capital cost of \$780/Kw. Consideration of the rate of change of the increase yields much higher capital costs. In testimony before the Joint Committee on Atomic Energy, AEC Commissioner Larson reported that estimates of capital costs have risen from about \$125/Kw installed to over \$500/Kw of installed capacity at some plants.(2)

By far the most detailed analysis of direct construction costs, only a part of capital costs, is to be found in AEC document WASH-1230 Volumes I and II. These two volumes indicate that for a 1000 MWe boiling water reactor, in 1971 the total base construction costs were $211,963,200, for a 1000 MWe pressurized water reactor the total base construction costs were $210,483,000. Escalating these costs at seven percent from January 1971, to January 1980, implies costs of $389,680,000 and $386,960,000 respectively. The document recommends that the prices must also be adjusted for contingency costs, including material, labor, and professional services, and for escalation and interest charges during construction. Furthermore, the estimates exclude the cost of land and land rights and assume the unrestricted availability of water, once through cooling, no provision for extended discharge, and no provision for restricted intake velocity or dilution in the cooling systems.[3]

For comparison, the Ontario Hydro-Electric Power Commission has indicated that the estimated cost of nuclear reactors in 1982 will be approximately $460/Kw installed.[4] Toledo Edison estimates the costs of its Davis-Bessee plant, due to be on-line in 1976, at $450 million.[5] However, this is for a 906 megawatt plant. Increasing the size of the plant to 1000 MWe and escalating at seven percent to 1980 yields a cost of $651/Kw installed. In the Arthur D. Little study referred to in Section I, direct capital costs, escalation and the allowance for funds during construction totalled $562/Kw for a plant to be completed in 1981. The addition of taxes, utility costs and contingency allowance brought total capital costs to $702/Kw.[6]

A 1971 study by Union Electric resulted in a basic capital cost estimate of $422/Kw for an 1175 MWe nuclear plant to be completed in 1980. Contingencies and escalation were reported to be appropriate to conditions in 1971. Once through

cooling was proposed. In a subsequent study, Union Electric recalculated the costs at $715/Kw including natural draft cooling towers. This was based on total construction expenditures for Callaway Unit No. 1 of $839 million. As the cooling tower is expected to cost $61 million, construction costs for 1981-82 operation, without the tower, are approximately $622/Kw of installed capacity.[7]

The two proposed Union Electric Callaway plants are part of a package of six identical plants known as the Standardized Nuclear Unit Power Plant System (SNUPPS) designed by the Bechtel Corporation and sold by Westinghouse. The advantages of this standardized package are asserted to be increased reliability and savings in costs of engineering, manpower, construction, start-up, operation, and procurement.[8] If successful, they may also minimize licensing problems for both the AEC and Westinghouse. It is possible that, in order to put the six package sale together and influence future buyers in standardization, Westinghouse and/or Bechtel were willing to set a comparatively low price on the first set of units.

Standardization possibly leads to the increased reliability and cost savings claimed. It is not impossible that standardization leads to the mass recalls experienced in the auto industry. It is not always clear that a standardized item is made with more care and precision than a unique item. It is probably cheaper.

Average 1980 capital costs for the Illinois Power Company's Clinton reactors have been estimated at $386/Kw by the company and $456/Kw by the staff of the AEC Directorate of Licensing.[9] These cost estimates have been challenged as too low.

It has already been pointed out that the capital costs associated with the UE SNUPPS contracts may be low. Reports in the <u>Wall Street Journal</u> and the <u>New York Times</u> indicate that Combustion Engineering may have also enabled the

utility industry to obtain temporary low prices for reactors. Apparently, this was done in order to increase market share. The low prices have been based on special warranties with respect to performance and required AEC changes. Moreoever, some utilities were apparently permitted to obtain no-cost contract cancellation clauses.[10] To the extent that the warranties are more than usually favorable to the utilities, the associated contingency reserve is reduced.

Reactor capital costs are likely to increase in the future. In part this is due to increasing finance costs which have led to a number of reactor delays and cancellations. Increasing costs have also been responsible, perhaps, for several utilities joining together to build a single reactor.[11] Delays in construction increase capital costs. Commonwealth Edison has said that, because of lengthy delays in the construction of the LaSalle County nuclear plant, it was increasing its construction budget by $300 million for the 1973-1977 period.[12] Furthermore, both GE and Westinghouse are attempting to renegotiate contracts, including some that have already been made, to include five to eight percent price increases. Contracts written after January 1974, have automatic escalation clauses.[13]

B. Cooling Systems

Next to the nuclear steam system, the major capital cost is the cooling system. Both in terms of direct cost and environmental impact the system choice affects the fossil-fissile alternative. Heat rejection from nuclear plants is about 50 percent greater than that from fossil plants. When comparing alternate power sources, neither the unit size nor the type of cooling system need be the same for both.

There are three basic types of cooling systems: 1) open cycle, 2) closed cycle, and 3) auxiliary cooling. The

first includes once-through cooling and lakes, lagoons or ponds. The second covers wet mechanical and natural draft cooling towers, spray channels, dry mechanical draft towers and wet/dry mechanical draft towers. Auxiliary cooling systems include lakes with wet mechanical draft towers or lakes with spray channels. There is evidence that the Environmental Protection Agency is moving toward requiring closed cycle cooling systems. In general, this means cooling towers rather than very large lake impoundments where all cooling is done by evaporation.

Cooling towers are not new. In September 1972, it was reported that of sixty commercial plants under construction or recently completed, twenty-one had cooling towers. Of the twenty one, there were ten closed cycle towers, five open cycle towers, and six combination types. Of the rest, twelve commercial plants utilized cooling lakes, three used diffuser type discharge systems, and twenty-two had once-through cooling.(14) Effective April 1, 1973, the Federal Power Commission indicated that for the 11 coal and 76 nuclear steam electric plants of 900 MWe and over, under construction or due to begin construction within two years, 38 would use cooling towers, 21 would have cooling lakes, and 24 anticipated using once-through cooling. Cooling systems for ten more plants were not specified. If it is assumed that all 11 of the coal plants plus one additional plant, for which the fuel was not specified, were to use cooling towers, then 26 nuclear plants would be using cooling towers and only 21 using cooling lakes. Apparently, cooling towers are considered desirable by more companies than are cooling lakes.(15)

It is difficult to assess the cost of cooling towers because what is included is not always specified. Costs for closed cycle towers have been reported in a range from $4-20 million, with average costs of $8-10/Kw for mechanical draft and $12-15/Kw for natural draft towers. Estimates made by the

Wisconsin Electric Power Company for a closed cycle system are $23 million for mechanical draft cooling towers and $32 million for natural draft cooling towers. Evaluating all costs over the life of the plant, Wisconsin Electric estimates that costs range from $45 to $56 million. Cooling tower costs for Commonwealth Edison's Dresden Units 2 and 3 totalled $30.7 million. By comparison, costs associated with the cooling lake for the Oconnee Nuclear Plant were estimated at $25 million.(16)

Two more recent cost estimates may also be noted. Consolidated Edison estimates the cost of a closed cycle system at the Indian Point Power site on the Hudson River at $70 million plus approximately $20 million/year for operating costs. They calculate that approximately one-eighth of the plant's 873 megawatts must be used to supply energy to the tower.(17) Consolidated Edison does not want the towers. By comparison, the American Electric Power Company has ordered three natural draft cooling towers at a total cost in excess of $25 million. The company has taken an option on two more towers.(18)

An interesting comparison of estimated costs of cooling system alternatives can be made by referring to Tables VI-1 and VI-2. It is, perhaps, superfluous to note that the Illinois Power Company prefers a cooling lake and Union Electric has opted for natural draft cooling towers. Unfortunately, this is not sufficient to explain the gross differences. The AEC Directorate of Licensing has already accepted the Illinois Power Company estimates for its own environmental statement. Table VI-3 is simply a copy of the Illinois Power Company submission. The Union Electric Company data were also prepared for AEC submission. The difference between the IPC and the UE estimates can be found in Table VI-4.

Perhaps most revealing is a comparison between the two companies' evaluation of land costs. It must be remembered that a) Illinois farm land is among the most costly in the mid-

TABLE VI-1

UNION ELECTRIC COMPANY
CALLAWAY PLANT, UNITS 1 and 2[a]

COMPARISON OF COSTS OF ALTERNATIVE COOLING WATER SYSTEMS
PARTIAL DISCHARGE WATER USE ARRANGEMENT

(Millions of Dollars)

	COOLING POND	SPRAY CANALS	NATURAL DRAFT COOLING TOWER	WET MECHANICAL-DRAFT COOLING TOWER - WOOD	WET MECHANICAL-DRAFT COOLING TOWER - CONCRETE	WET-DRY MECHANICAL-DRAFT COOLING TOWER
Capital Costs 1982[b]						
Land	15.30	1.75	0.05	0.08	0.08	0.11
Construction and Equipment	276.03	63.82	61.01	46.16	52.27	58.51
Subtotal	291.33	65.57	61.06	46.24	52.35	58.62
Operating Costs						
Total O&M (1982-2011) Present Worth	144.43	115.77	76.10	101.48	93.50	114.69
Total Costs						
Present Value 1982	435.76	181.34	137.16	147.72	145.85	173.31
Annualized Costs						
Present Value 1982	37.29	15.52	11.74	12.64	12.48	14.83
Percent of base	317.6	132.2	Base	107.7	106.3	126.3

[a] Costs based on 2 units.

[b] Includes equivalent costs of generation capacity required for each alternate, escalations and interest during construction.

Source: Union Electric Company, Testimony before the Missouri Public Service Commission, Case No. 18177, Table 10.1-1.

TABLE VI-2

ILLINOIS POWER COMPANY, CLINTON PLANT, UNITS 1 AND 2
COMPARISON OF COSTS OF ALTERNATIVE COOLING WATER SYSTEMS
($ Million)

	Lake	Spray Channel	Lake with Spray Channel	Wet Natural Draft Cooling Tower	Mechnical Draft Cooling Towers			Lake with Wet Mechanical Draft Cooling Tower
					Wet	Dry	Wet/Dry	
1. Land and Equipment Costs								
a) Lake and Land Costs (each unit)	14.26	14.54	14.26	13.62	13.62	1.34	13.43	14.26
b) Equipment, Construction and Miscellaneous Costs (each unit)	3.97	14.35	6.38	18.88	12.84	105.05	36.12	7.45
c) Top charges, Escalation and Allowance for funds used during construction	13.40	21.23	15.17	23.88	19.41	78.18	36.41	15.96
2. Subtotal - Land and Equipment	31.63	50.12	35.81	56.38	45.87	184.57	85.96	37.67
3. Operation and Maintenance								
a) Total Maintenance (each unit $000/yr.)	7.0	93.5	38.7	241.0	255.5	515.5	237.9	23.5
a[1]) Total Equivalent Capital Investment of Maintenance (each unit - 30 years 13.11 percent fixed charge rate)	.05	.71	.30	1.84	1.94	3.93	1.81	.18
b) Total Equivalent Capital Investment of Fuel Cost (30 year plant life)	62.24	63.16	62.73	63.18	62.22	67.97	63.93	62.83
4. Subtotal - O&M present worth	62.29	63.87	63.03	65.02	64.16	71.90	65.74	63.01
5. Total (Lines 2 and 4)	93.92	113.99	98.84	121.40	110.03	256.47	151.70	100.68

Source: Derived from Illinois Power Company, Environmental Report, Clinton Power Station Units 1 and 2, Construction Permit Stage, Volume 4, Appendix 10A, Table 10A-1.

TABLE VI-3

ILLINOIS POWER COMPANY,
COMPARISON OF ALTERNATIVE COOLING SYSTEMS

Incremental Equivalent Capital Investment (one unit, $ million)	Open-cycle	Closed-cycle Systems (with lake as reservoir)					Auxiliary Cooling[c]	
	Lake (reference system)	Wet Mechanical-Draft Towers	Wet Natural-Draft Towers	Spray Channel	Dry Mechanical-Draft Towers	Wet/Dry Mechanical-Draft Towers	Lake with Wet Mechanical-Draft Tower	Lake with Spray Channel
Capability[a]	0	7.0	8.5	7.8	48.5	12.0	2.7	1.4
Fuel Cost[b]	0	1.0	0.9	0.9	5.7	1.7	0.6	0.5
Maintenance	0	1.9	1.8	0.7	3.9	1.8	0.1	0.2
Construction	0	14.3	24.7	18.5	152.9	54.3	6.0	4.2
Total (one unit)	0	24.2	36.0	27.9	211.0	69.8	9.4	6.3
Total (two units)	0	48.3	72.0	55.7	422.1	139.5	18.9	12.6
Salient Environmental Effects	Higher lake temperature, consumption of water.	Visual, noise, occasional nearby fog, increased consumption of water.	Visual, increased consumption of water.	Occasional nearby fog, increased consumption of water.	Visual, noise, no consumption of water.	Visual, noise, occasional nearby fog, reduced consumption of water.	Visual, noise occasional nearby fog, some increase in consumption of water.	Occasional nearby fog, some increase in consumption of water.

Based on applicant's estimates (Applicant's Environmental Report, Appendix 10A, Table 10A-1).

[a]Capital cost (at $400 per KW) of additional generating capacity to compensate for reduced station output.

[b]Capitalized cost of additional fuel required because of reduced efficiency and consumption of auxiliary power.

[c]Auxiliary cooling capacity arbitrarily sized to provide a maximum discharge temperature to the lake of 95°F.

Source: Atomic Energy Commission, Directorate of Licensing, Draft Environmental Statement, related to the proposed Clinton Power Station Units 1 and 2, Illinois Power Company, Docket Nos. 50-461 and 50-462, October 1974, Table 9.6, page 9-16.

TABLE VI-4

COOLING SYSTEMS: COMPARATIVE COSTS
ILLINOIS POWER COMPANY vs.
UNION ELECTRIC COMPANY

($ million -- UE base)

	Land and Equipment Costs			
	Land	Construction, Etc.	Operation and Maintenance	Total
Cooling Pond	(1.04)	(258.66)	(82.14)	(341.84)
Spray Canals	12.79	(33.24)	(51.90)	(67.35)
Natural Draft Cooling Tower	13.57	(18.25)	(11.08)	(15.76)
Wet Mechanical Draft Cooling Tower - Wood	13.94	(13.91)	(37.32)	(37.69)
- Concrete	13.94	(20.02)	(29.34)	(35.82)
Wet/Dry Mechanical Draft Cooling Tower	14.15	14.02	(48.95)	(21.61)

Source: Tables _____ and _____

Note: Cooling pond--land (1.04) means that the Illinois Power Company estimate was $1.04 million below the Union Electric Company estimate for a similar facility subcategory.

west, b) closed-cycle systems use less land than does a lake and c) a spray pond requires only five percent of the area required for a cooling pond due to the increased heat transfer coefficient.(19) Considering only land and equipment, if the IPC estimates for the lake are substituted in the UE table, the capital cost subtotal in Table VI-1 is $31.63 million. Therefore, the present value of the total cost is $176.06 million. According to UE's estimates, this is still more expensive than any alternative except spray canals. Alternatively, using UE's land costs in the IPC table, yields the following total costs:

	LAND AND EQUIPMENT SUBTOTAL ($ Million)	TOTAL COST ($ Million)
Spray Channel	37.33	101.20
Natural Draft Cooling Tower	42.81	107.83
Wet Mechnical Draft Cooling Tower	32.33	96.49
Wet/Dry Mechnical Draft Cooling Tower	72.64	138.38

From the background information provided, there appears to be no way to reconcile the differences in the total operating and maintenance costs supplied by the two companies. If the relevant Illinois Power Company O&M costs are substituted in the UE comparative cost table, total costs become:

UNION ELECTRIC TOTAL COSTS
(IPC O&M Costs)

Cooling pond		$353.62 million
Spray canals		$129.44 million
Natural draft cooling tower		$126.08 million
Wet Mechanical Draft Cooling Tower	- Wood	$110.40 million
	- Concrete	$116.51 million
Wet/Dry Mechanical Draft Cooling Tower		$124.36 million

One can understand perhaps, gross differences in the estimates of land costs. The differences listed for equipment, construction, miscellaneous, escalation, etc., and for operations and maintenance for the cooling towers and other systems appear irreconcilable.

C. Nuclear Safety

The issue of the safety of nuclear reactors is beyond the scope of this study. However, to the extent that questions of safety and their solutions arise, the costs of nuclear power increase. Certainly, contingency allowances increase.

1. Emergency Core Cooling Systems

Following a two year hearing, the Atomic Energy Commission issued new preliminary emergency core cooling system regulations to be effective August 1974. The rules reduced fuel rod temperatures and the level of permissible oxidation of the metal cladding on the rods. However, the primary question of the adequacy of the emergency core cooling system itself remained. Tests of the hardware, rather than computer simulation models, are not expected to be completed before

1976.[20] Even to comply with current regulations, some plants may have to retrofit, others may reduce their electrical output or shift the placement of rod bundles. The cost effect of the current regulations will be felt primarily by utilities owning reactors now being constructed or that have already been built. Prior to the decision, an early estimate of the cost of the rule changes included an average five percent derating of all reactors through mid-1976, plus approximately $193 million for replacement power plus $70 million/1000 megawatt reactor or $35 million/500 megawatt reactor for modifications and bringing the plant back to 100 percent of rated capacity. Moreover, there would be a fuel cost penalty of approximately $520,000/year/1000 MWe reactor and $215,000/year/500 MWe reactor. If further derated, capacity and replacement power penalties are exptected to increase substantially.[21] It is possible that, subsequent to the tests on the emergency core cooling system hardware, additional changes in regulations and requirements will be made. These will further increase costs of construction and retrofit.

While the emergency core cooling system is the largest and most important item of cost subject to change, there have been a number of problems and equipment failures, reported in the general and trade press, with respect to both the nuclear steam system and the non-nuclear systems. These have involved design, quality control, and basic understanding of engineering at the tempertatures, pressures, and special atmospheres involved in reactors. All of these lead to costs in terms of construction, maintenance, repair and purchased electricity, sometimes over long periods of time. It has been argued that among the problems of reactor construction is the fact that the reactors currently being built are all unique. Westinghouse has pioneered standardization with the construction of six identical reactors, arguing that standardization will lead to better quality control and better engineering. Because

of their size, however, reactors must be field assembled even if most of the components are built elsewhere. Furthermore, while it is possible that standardization will lead to better quality control, it is not impossible that standardization of nuclear power components can, like the auto industry, lead to massive recalls. The recent example of pipe cracks in the primary cooling system of a number of GE boiling water reactors is a case in point.[22]

2. Radioactive Wastes

Radioactive wastes are vented to the air from reactors and can be found in the reactor effluent. This is permissible within prescribed limits. However, these limits are subject to change. Changes, however, are costly. For example, it has been estimated that for a boiling water reactor, to cut the dosage of iodine-131 to an offsite individual from 25 millirems per year to 0.04 millirems per year requires a capital cost of $3.48 million. To cut the dosage from 25 to one millirem per year, the capital cost is $2.8 million. Retrofit costs are higher. With a pressurized water reactor, to reduce the dosages as noted above is much more expensive. It is considered impossible to reach the low levels of a boiling water reactor at any cost.[23]

3. Decommissioning

Under current regulations the Atomic Energy Commission generally requires that all quantities of source, special nuclear, and by-product materials not exempt from licensing under Parts 30, 40, and 70 of Title 10, Code of Federal Regulations, either be removed from the site or secured and kept under surveilance. To date only six nuclear electric generating stations have been decommissioned. Four of these were Commission owned and operated facilities. Several alternative modes of decommissioning have been experienced in these cases. They

may be summarized generally as four alternative levels of restoration of the plant site, each with a distinct level of effort and cost. At any level, economically salvagable equipment and all reactor fuel elements are removed. Some equipment will be decontaminated and wastes of the type normally shipped during operation will be sent to waste depositories. However, the following restoration measures would then have to be taken.

1) At the lowest level there would be minimal dismantling and relocation of radioactive equipment. All radioactive material would be sealed in containment structures, primarily existing ones, which would require perpetual, continual surveilance for security and effectiveness.

2) At the next level some radioactive equipment and material would be moved into existing containment structures to reduce the extent of long term containment. Surveilance as in the lowest level would be required.

3) At the third level radioactive equipment and materials would be placed in a containment facility approaching a practical minimum volume. All unbound contamination would have been removed. The containment structure would be designed to meet minimal perpetual maintenance surveilance and security.

4) At the highest level all radioactive equipment and materials would be removed from the site. Structures would be dismantled and disposed of on-site by burial or offsite to the extent desired by the tenant.

It may be noted that in all but the highest level, the nuclear program would leave the nation dotted with cenotaphs. The AEC estimates the cost of decommissioning at the lowest level to be about $1 million, plus a maintenance charge on the order of $100,000/year. The estimates vary from case to case, because of differing assumptions as to the level of restoration. For example, the AEC expects that complete restoration, including regrading, would cost about $70 million. They point out that at present land values it is not likely that consideration of an economic blanace alone would justify a particular level of restoration.(24)

In the specific case of the Illinois Power Company, no decommissioning plans are given.(25) Despite the lack of information, the Atomic Energy Commission has estimated that decommissioning costs in 1981 are $50 million for the nuclear power plant with escalation at 6.0 percent and discounting at 8.75 percent for a net discount rate of 2.75 percent over thirty years, the result is a present value of decommissioning of $22.2 million. With an 80 percent load factor, this results is a levelized cost of 0.13 mills/Kwhe.(26)

SECTION VI FOOTNOTES

1. Atomic Industrial Forum, Nuclear Industry, April 1972, p. 12.

2. U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, 93 Cong. 1 Sess., Hearing, Part I, Phase I, July 31 and August 1, 1973, p. 29.

3. United Engineers and Constructors, Inc., Boiling Water Reactor Plant: 1,000-MWe Central Station Power Plants, Investment Cost Study, U.S. Atomic Energy Commission, WASH-1230, (Vol II), June 1972, Table I-1 and Op. Cit., (Vol. I), June 1972, Table I-1.

4. Wall Street Journal, November 20, 1973.

5. Wall Street Journal, September 26, 1973.

6. Arthur D. Little, Inc., A Study of Base-Load Alternatives for the Northeast Utilities System, July 5, 1973, Table 7.

7. H. Clyde Allen, Affidavit before the Public Service Commission of Missouri, Case No. 18,117, September 5, 1974, pp. 47-48, and M. T. Welshans, Affidavit before the Public Service Commission of Missouri, Case No. 18,117, September 5, 1974, p. 4.

8. Charles J. Dougherty, Affidavit before the Public Service Commission of Missouri, Case No. 18,117, September 5, 1974, p. 8.

9. Atomic Energy Commission, Directorate of Licensing, Draft Environmental Statement, related to the proposed Clinton Power Station Units 1 and 2, Illinois Power Company, Docket Nos. 50-461 and 50-462, October 1974, Table 9.4, p. 9-8.

10. Wall Street Journal, May 7, 1974 and May 13, 1974, and New York Times, May 10, 1974.

11. Wall Street Journal, August 1, 1974 and August 14, 1974.

12. New York Times, October 4, 1973.

13. Wall Street Journal, September 3, 1974 and September 5, 1974.

14. Atomic Industrial Forum, Op. Cit., September 1972, pp. 11-12.

15. Federal Power Commission, News Release, No. 19620, September 12, 1973, Table 6 and 8.

16. Atomic Industrial Forum, Op. Cit., September 1972, pp. 11-13.

17. New York Times, October 17, 1973.

18. Wall Street Journal, March 22, 1974.

19. Dynatech R/D Company, A Survey of Alternate Methods for Cooling Condenser Discharge Water: Large-Scale Heat Rejection Equipment, Environmental Protection Agency, Water Quality Office, July 1969, p. 29.

20. Questions of safety based on computer runs have been raised by RAND (Wall Street Journal, November 6, 1973). The possibility that the AEC has repeatedly suppressed internally generated adverse safety reports and studies has also been reported (New York Times, November 10, 1974).

21. Atomic Industrial Forum, Op. Cit., May 1973, pp. 13-15.

22. Wall Street Journal, September 27, 1974 and October 25, 1974.

23. Atomic Industrial Forum, Op. Cit., May 1972, pp. 19-21.

24. Atomic Energy Commission, Directorate of Licensing, Op. Cit., p. 10-3.

25. Ibid., p. 10-4, and Illinois Power Company, Environmental Report, Clinton Power Station Units 1 and 2, p. 5.9-1.

26. Atomic Energy Commission, Directorate of Licensing, Op. Cit., Table 9.4, p. 9-8.